GRI-00/0193

GRI
FINAL DRAFT

TOPICAL REPORT

NATURAL GAS TRANSMISSION PIPELINES
PIPELINE INTEGRITY
PREVENTION, DETECTION & MITIGATION PRACTICES

Prepared by:

THE HARTFORD STEAM BOILER
INSPECTION AND INSURANCE COMPANY

Gas Research Institute
Pipeline Business Unit

DECEMBER 2000

-

Acknowledgements

The authors acknowledge the leadership and support provided by many individuals in the preparation of this document. The Interstate Natural Gas Association of America (INGAA) and Gas Technology Institute (GTI) worked closely to provide input, direction, review and support. This work was conducted under the direction of John Zurcher of Columbia Energy and Keith Leewis of GTI.

In addition, a number of individuals provided input, review and/or comments that helped to significantly improve the final document and make it more inclusive.

Thank you to:

Terry Boss, INGAA
John Chin, ANR
Andy Drake, Duke
Bill Gute, DOT-OPS
Dave Johnson, Enron
Fred Joyner, DOT-OPS
John Kiefner, Kiefner Associates
Wes McGehee, Consultant
Roy Pugh, Duke
Paul Wood, Cycla

We also wish to acknowledge the prior significant effort the American Petroleum Institute (API) member companies and Marty Matheson had in developing an integrity management standard for liquid pipelines. Many concepts within the standard as well as specific tables and figures served as a basis for comparison as this document was drafted.

Thank you all.

Mark Hereth, Ted Clark, and Bernie Selig

NATURAL GAS TRANSMISSION PIPELINES
PIPELINE INTEGRITY
PREVENTION, DETECTION & MITIGATION PRACTICES

Executive Summary

There are approximately 325,000 miles of natural gas transmission pipelines in the United States, that transport natural gas from gathering lines and processing plants across the country to local distribution companies (LDCs) that distribute the gas to homes and businesses.

Transmission pipeline companies spend a large part of their operating budgets to ensure that pipelines run safely and reliably. A recent GAO report states, “Fatalities from pipeline accidents are relatively low when compared with those from accidents involving other forms of transportation.” The Gas Research Institute published report # GRI-00/077 – “The Safety Performance of Natural Gas Transmission and Gathering Systems” which describes the safety performance of gas transmission pipelines over the past 14 years. While the industry’s safety record is a good one by any measure, it is never good enough.

OPS is developing a new pipeline safety rule – “Pipeline Integrity Management in High Consequence Areas”, to ensure a comprehensive and integrated approach to pipeline integrity in High Consequence Areas (HCA’s).*

Gas transmission pipelines must adhere to various Federal Government regulations from the Department of Transportation (predominately 49 CFR Part 192), Environmental Protection Agency, U.S. Army Corps of Engineers and Occupational Safety and Health Administration.

Many transmission pipeline companies have programs to prevent pipeline failures, detect anomalies and perform repairs to maintain and improve pipeline integrity and reliability. These programs significantly exceed all the regulatory minimums.

This report shows how the existing pipeline regulations address each of the causes of pipeline failures. It also shows how industry general practices and voluntary research have addressed and exceed the regulatory minimums. Unlike most regulations, 49 CFR 192 addresses age-related deterioration through periodic leak testing, patrols and when the population density increases, mandatory replacement of serviceable pipe with new, heavier wall pipe to mitigate the consequences of mechanical damage and potential corrosion.

The following conclusions can be drawn from this study and information taken from the listed references:

- While gas transmission pipelines are the safest method of energy transportation* (per GAO), the industry continually strives to improve its safety and reliability record.

*See Definitions – page 44

- DOT’s regulation 49 CFR 192 for gas transmission pipelines contains provisions that address each of the causes of failures.

- The industry has voluntarily spent more than $100 million over the past 5 years on safety and reliability research and development, and $33 million just in the areas of inspection and maintenance. Through appropriate investment now and in the future, developing and new technologies for prevention, detection and repair of pipelines will continue to have a significant, positive impact on pipeline safety.

- DOT's regulations for gas transmission pipelines uniquely require the identification of and additional protection for higher population areas in the proximity of gas pipelines through "class" location design and operations requirements.

- Many pipeline companies significantly exceed regulatory requirements in their operations.

- Maintaining pipeline safety and reliability is a complex process. There are presently more than 60 different prevention, detection and mitigation practices (not including many of the 130 Common Ground reported best practices*) that are applied to the line pipe individually, sequentially or collectively to assure pipeline integrity. Current regulations require companies to have selected aspects of a comprehensive integrity management plan within their Operations and Maintenance Plan.

- Many pipeline companies use some form of risk-based analysis to assess the condition of their system and to prioritize their prevention, detection and mitigation efforts.

- The pipeline industry is continually updating industry standards that enhance pipeline system safety.

- A comparison of total systems versus class 3 and 4 incidents shows that the rates of incidents are comparable, the majority of class 3 and 4 incidents are due to third-party damage and their net consequences are no deaths, 16 injuries (10 through third-party damage) over a 15-year period.

- Based on presented data, it is important to recognize that while pipelines within High Consequence Areas (HCAs) are an important safety issue, the remaining system's integrity must be carefully addressed as well. Regulations should be framed to permit the industry the ability to provide the most effective safety on a system-wide basis, reducing the frequency of failures as well as the consequences.

*Common Ground Report (see DOT Website)

NATURAL GAS TRANSMISSION PIPELINES
PIPELINE INTEGRITY
BY PREVENTION, DETECTION & MITIGATION PRACTICES

Table of Contents

Section 1 – Introduction

The Natural Gas Transmission Pipeline Industry is comprised of more than 1,000 companies, large and small, which operate approximately 325,000 miles of gas transmission pipelines. These pipelines are the conduit that connect the gas production, storage and gathering fields to the distribution pipelines in each region of the country that ultimately reach the end user. Transmission pipeline companies are dedicated to operating safe and reliable systems. The Office of Pipeline Safety (OPS), under the Research & Special Projects Administration of the Federal Department of Transportation is the government organization responsible for interstate transmission pipeline safety.

OPS is developing a new pipeline safety rule – "Pipeline Integrity Management in High Consequence Areas", to ensure a comprehensive and integrated approach to pipeline integrity in High Consequence Areas (HCA's). A framework for a standard for pipeline integrity management is presented in this document. An outline of both a process for developing an Integrity Management Plan as well as what might be included in such a plan are described to provide a potential framework for a gas pipeline industry standard for Integrity Management in HCA's.

This report describes the industry's safety record, the existing regulatory requirements for safe operation, the practices that the industry uses to meet and exceed the regulatory requirements and the research and development that is being performed to continue to improve the industry's practices and safety record. These are related throughout the report to 22 causes or threats to pipeline integrity developed by the industry.

The original scope of this document was to identify and document current industry inspection and maintenance practices. An open industry meeting was held in Houston in June 2000. The purpose was to document those practices that are used to achieve compliance with 49 CFR 192 and also document those practices that achieve greater levels of safety performance. It was recognized that use of the terms "inspection and maintenance" was not broad enough to convey what the industry was currently doing. The scope was adapted to reflect the more proactive efforts that were spawned from the work of the Risk Management Quality Action Teams of the mid-1990s and best practices for damage prevention in the years that followed. It was determined that these practices were better characterized through the use of "prevention, detection and mitigation/replace". These practices are related throughout the report, to 22 causes or threats to pipeline integrity. A significant amount of information has been included in this report on what has and is occurring in the pipeline industry in order to learn from the past, determine where gaps exist and plan for the future informatively.

While the industry's safety record is a good one by any measure, it is never good enough and the industry spends a great deal of money to continue to improve pipeline integrity and reliability. This report identifies and describes a set of practices to prevent and detect threats to pipeline integrity. It also describes past and present R&D directly related to prevention, detection, and mitigation of pipeline defects. Mitigation is used throughout this report to indicate the spectrum of options from repair, replacement or continued monitoring of the condition.

The data and information provided in this report are intended as the background information for the formulation of effective regulations for pipeline integrity. It may also serve as a useful resource for various constituencies to better understand what the industry presently does to maintain pipeline integrity and the newer technologies that are "in the pipeline" that will contribute to future pipeline safety. A list of definitions and acronyms frequently used in the pipeline industry are included in the rear of this report, to make this report useful for a variety of audiences.

Section 2 – Background: Integrity Management of Natural Gas Pipelines

Integrity Management is a systematic process for continually assessing, evaluating and remediating the integrity of systems through prevention, detection and mitigation practices, comprehensively evaluating and integrating all data and analyses, in an iterative manner.

The ASME code for natural gas pipelines, B31.8, embodies many provisions now considered in managing integrity, including material specification, design, welding, construction, testing requirements, and operating and maintenance requirements. A code for pressure piping was first drafted in 1935, and has undergone revision through the years via the ASME consensus standards development process.

It is noteworthy that the elements of B31.8 when rigorously applied yield line pipe that shows virtually no degradation or age effect over time. B31.8, and its companion B31.4 for liquid pipelines are the only codes for the use of steel in commerce that embody a fundamental approach when rigorously applied will create operating conditions that minimize the degradation of line pipe over time. The approach is based on proper selection of materials, sound engineering design, application of cathodic protection (and where applicable, coatings), operation within the MAOP (Maximum Allowable Operating Pressure) and maintenance of the cathodic protection systems. All other ASME codes presume degradation of in service materials. Sections of line pipe that have been cut out demonstrate this phenomenon. Line pipe in excess of 50 years in service can appear almost as new, showing no sign of degradation. However, when these precautions and protective systems are not in place or are not carefully managed, the integrity of the steel can be compromised. Hence, the need for integrity management.

Many aspects of the ASME Code were codified into a set of Minimum Federal Safety Standards for Transportation of Natural and Other Gas (Including Hydrogen!) by Pipelines (49 CFR Part 192) beginning in August of 1970. These regulations stipulated requirements for materials, design, design of pipeline appurtenances, welding, construction, and operation and maintenance. Requirements for corrosion control were added in 1971. The regulations were amended over the next thirty years, as technology advances were commercialized (e.g.-use of ClockSpring™ for repairs and performance-based repairs). In 1999, requirements for qualifications of operators were added to reduce the potential for human error.

ASME B31.8 also included a risk-based approach for establishing allowable operating pressures based on the relative density of the population surrounding the pipeline. These provisions were incorporated into the Minimum Federal Safety Standards in June of 1996. The approach applies a safety factor that reduces the maximum allowable operating pressure based on the density of the surrounding population. The greater the population density, the greater the safety factor, and hence the lower the allowable operating pressure and/or increased wall thickness of the pipe.

Following the pipeline incident in Edison, New Jersey in 1994, the Interstate Natural Gas Association of America (INGAA) formed a Pipeline Safety Task Force that established the Safety Action Plan to address improvements in:

One-call systems
Training
Contractor education
Non-destructive testing
Automatic shut-off valves, and
Risk Management.

While the plan did not specifically refer to integrity management, it was recognized that there were gaps in the code and regulations as listed above. The improvements and advances made in each of these areas were perceived to close these gaps. The net result was an improvement in the integrity of natural gas pipeline systems. INGAA, with support from the Gas Research Institute (now GTI), worked with representatives of the Office of Pipeline Safety, state regulatory officials and members of public interest groups in each of these areas.

GRI published a four volume set of documents that examined the state of risk assessment and risk management in the natural gas pipeline industry, and documented the extent of it's application in other industries. INGAA and OPS worked together to form the Gas Risk Assessment Quality Action Team to draw upon this work to evaluate the feasibility of allowing regulatory flexibility using risk management principles. The outcome is focused on improving safety and reliability. A team was subsequently formed that comprised representatives from hazardous liquid and natural gas companies, as well as a diverse group of government officials to develop an interim standard for risk management. This standard serves as the basis for companies making application to enter into a demonstration program established by Congress in the reauthorization of the Pipeline Safety Act in 1996.

One of the drawbacks of the current regulatory structure was that it lent itself to viewing the pipeline in a compartmentalized way. Managing integrity was often viewed as a set of activities as opposed to an integrated process. This code compartmentalization was reflected in the way companies were organized; separate departments for engineering, corrosion control, etc. The most significant aspect of these new risk management efforts was that companies began to view their systems in a holistic, comprehensive manner. Risk identification led companies to begin to integrate data on the condition of the system with the design, work history, service and the environment in which the pipeline operated. This was the beginning of an area now identified as being critical to integrity management, namely data integration. Finally, risk management has the same objective as integrity management—to improve the safety and reliability of the pipeline system.

The safety performance of the industry is in part a result of these integrity management measures discussed above, being in effect. Fig. 2-1 shows the trend of number of incidents from 1985 to 1998 and on a normalized basis to the amount of gas being transmitted per year. Fig. 2-2 tracks the number of incidents per year, separating on-shore from offshore incidents. Figure 2-3 shows the number of incidents that have occurred during that reporting period in the 4 different class locations defined in 49 CFR 192.

The gas transmission pipeline industry funded and continues to fund, research of the DOT incidence data to guide it into appropriate paths for continuous improvement. Recent analysis of DOT Reportable Incidents for Gas Transmission Pipelines and Gathering Systems Pipelines (Ref. 2) classifies the reportable incidents into 22 distinct causes. GRI report (Ref. 3 GRI-00/0077) The Safety Performance of Natural Gas Transmission and Gathering Systems, analyzes the safety performance of transmission lines by the 22 distinct causes. Figure 2-4 shows the number of incidents by a consolidated version of the 22 causes (see Ref. 3 for details) for both onshore and off shore transmission pipelines.

To ensure objective completeness, Table 2-1 has been updated to include all incidents through July 2000, and the unfortunate incident in Carlsbad, NM. Table 2-1 compares total gas transmission systems incidents with those in Classes 3 & 4, which were used as a surrogate to represent High Consequence Areas.

The Government Accounting Office issued a report in May 2000 on the state of pipeline safety (GAO/RCED-00-128, PIPELINE SAFETY). The report states: *"From 1989 to 1998, pipeline accidents (all oil & gas pipelines) resulted in an average of about 22 fatalities per year. On average, about 66 people die each year from barge accidents, about 590 from railroad accidents, and about 5,100 from truck accident. ……. Most fatalities and injuries occurred as a result of accidents on pipelines that transport natural gas to homes and businesses (primarily intrastate pipelines), while most property damage occurred as a result of accidents on pipelines transporting hazardous liquids (primarily interstate pipelines). ……. The Office of Pipeline Safety's data on the causes of pipeline accidents is limited to a few categories, (expected to increase to 22 in 2001). But these limited data indicate that the damage from outside forces, such as excavation, is the primary cause of such accidents."*

While each person or organization should evaluate this data and draw their own conclusions, several incontrovertible facts do present themselves:

- There are approximately 50 incidents per year (avg. over 15 years) on interstate gas transmission pipelines and less than 10% of these occur in Class 3 &4 locations. (Note: the miles of Class 3&4 comprise approximately 10% of the total mileage.)

- There have been no fatalities (even considering Carlsbad) in the higher population density Class 3&4 locations in 15 years. There have been 16 injuries during this same time frame, 10 of which were a result of third-party damage (TPD).

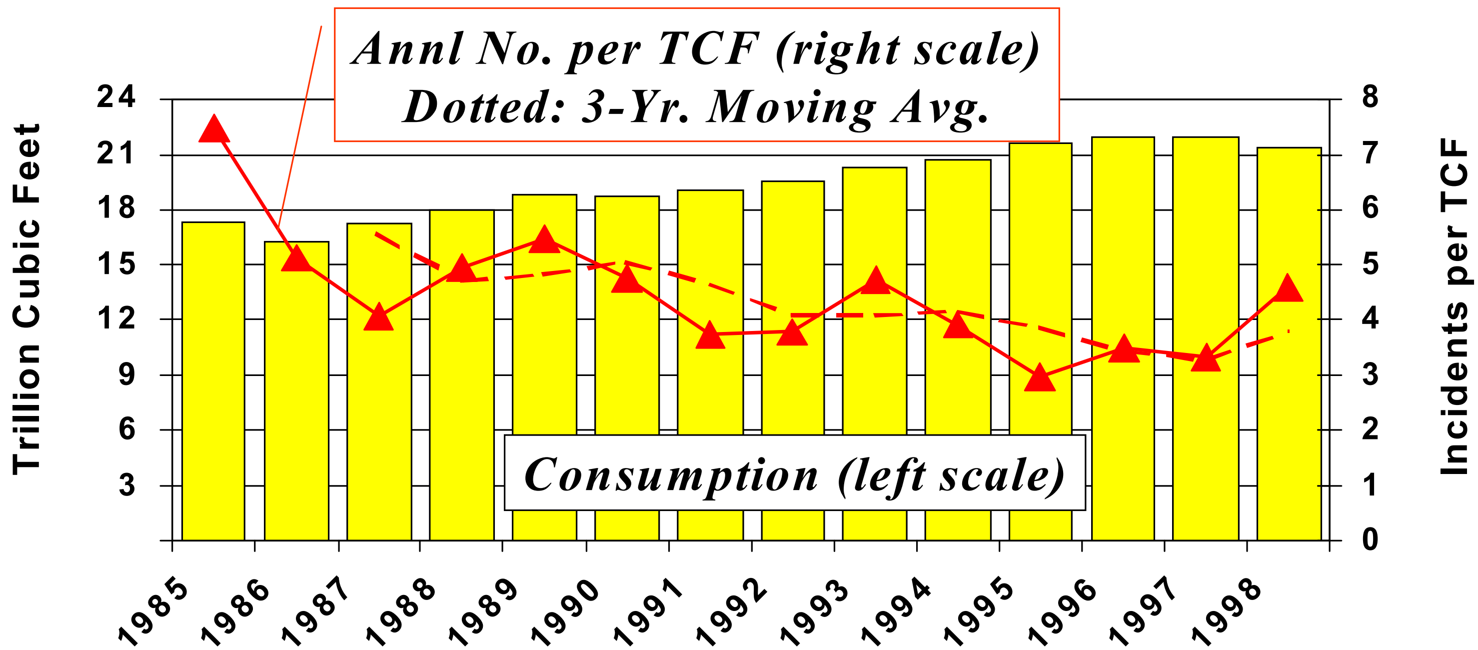
- From a total system perspective (Natural Gas Interstate Transmission), there have been 151 injuries and 34 fatalities in 15 years.

- Thirty percent of all of the incidents are caused by TPD. Approximately 85% (Ref. 15) of these occur immediately as the excavator strikes the pipeline. For class 3 and 4, more than 50% of the incidents are caused by third-party damage.

While the safety record is exemplary, recent tragic incidents such as those in Bellingham, Washington and Carlsbad, New Mexico underscore the need to continuously improve safety. In addition, industry and government recognized that there were potential gaps in the code (and therefore the regulations) that could be addressed through advances in technology and improvements in practices developed by pipeline operators. Accordingly, INGAA/GRI formed a task group in January 2000 to review the code, current industry inspection and maintenance practices, to provide data and information for OPS to consider in rulemaking directed at further improving the integrity of the natural gas pipeline system in America. This document was prepared to provide that input.

A llegro ENERGY GROUP

1985-98: Incidents Fall while Natural Gas Consumption Rises



Source: Safety Incidents from Office of Pipeline Safety database* of RSPA Form 7100.2 filings; consumption in trillion cubic feet (TCF) from Energy Information Administration.

*For Regulated Interstate Transmission & Gathering Lines

Figure 2-1

-

Interstate Trans. & Gath. Systems: Offshore Incidents Account for 23%

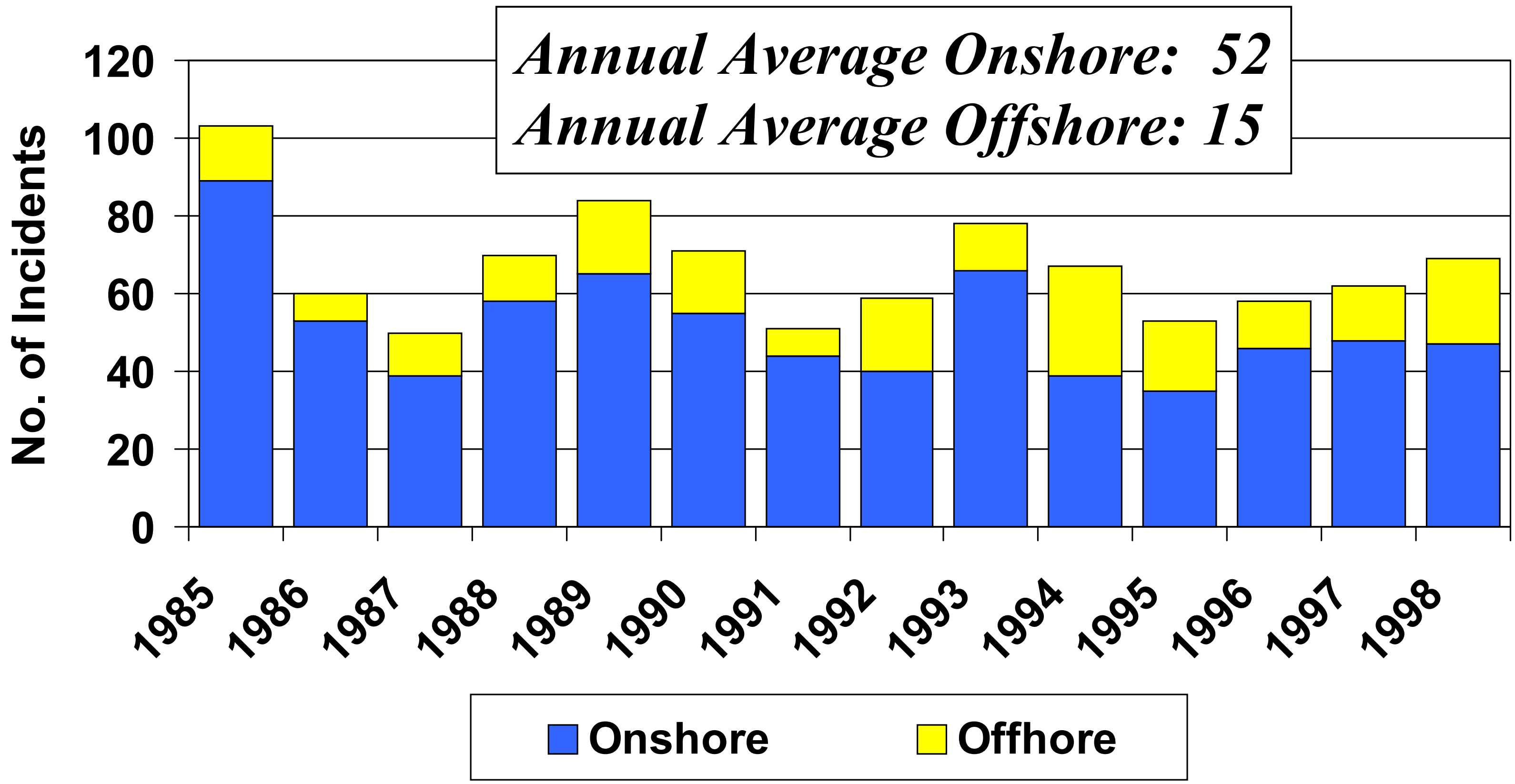


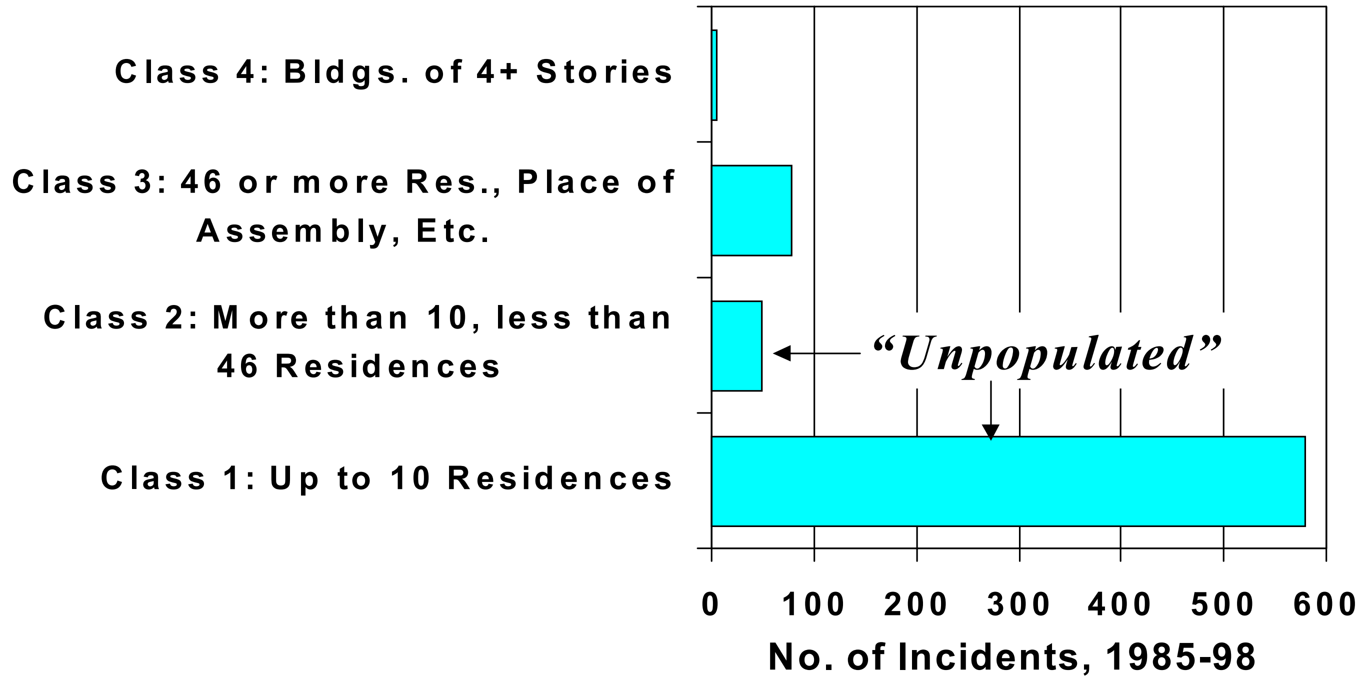
Figure 2-2

Note: Interstate Transmission and Gathering Operators. Based on RSPA Form 7100.2.

-

Transmission & Gathering Systems: Almost 90% Occur in Unpopulated Areas

Onshore Incidents by Class Location

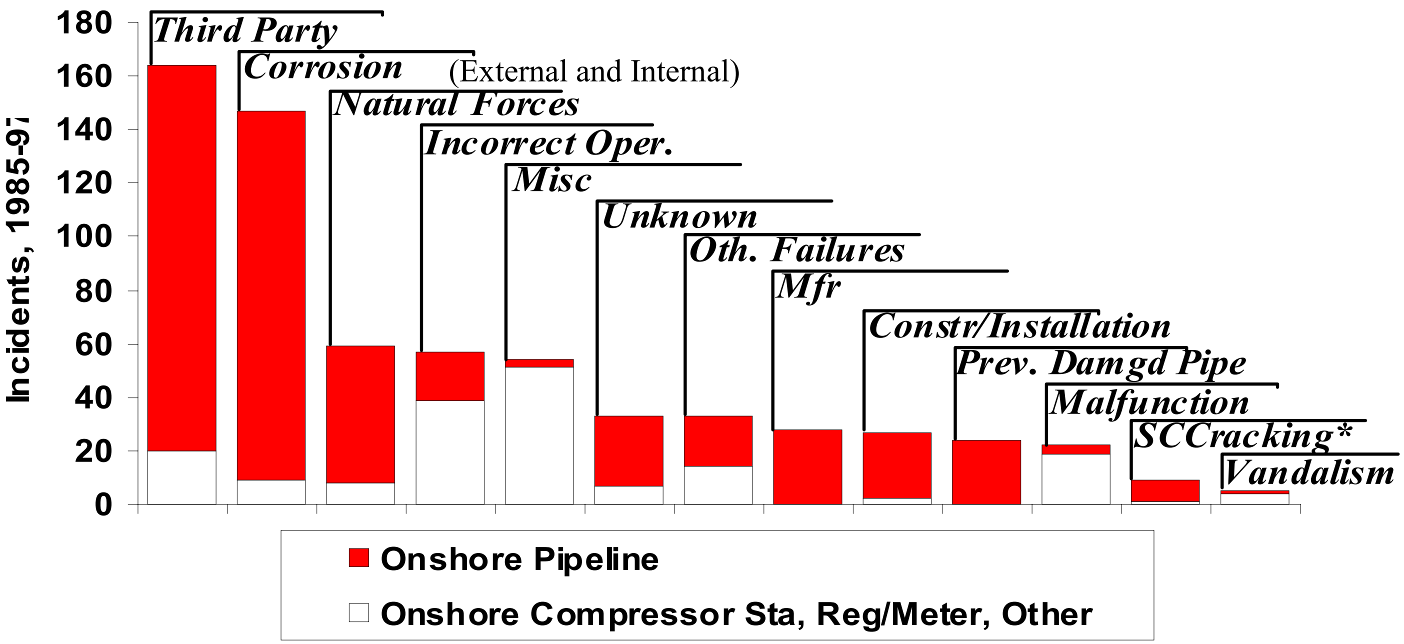


Based on RSPA Form 7100.2 for incidents involving Transmission and Gathering Operators, both inter- and intrastate. Excludes incidents involving operators that file a RSPA's Distribution System Annual Report. Excludes 12 (out of 724) onshore incidents where Class Location is unknown.

Figure 2-3

-

PRC International's Causes: Third Party Damage Most Important



*SCCracking: Stress Corrosion Cracking.
Recompilation of Keifner and Associates analysis of RSPA Form 7100.2 for Pipeline Research Committee International (Contract No. PR-218-0801). Excludes incidents involving operators that file RSPA's Distribution System Annual Report, Form 7100.1-1).

Figure 2-4

-

Impact Comparisons – Total System vs Classes 3 and 4 Line Piping

Table 2-1

	Incidents		**Fatalities**		**Injuries**	
Cause	**Total Sys**	**Class 3&4***	**Total Sys**	**Class 3&4***	**Total Sys**	**Class 3&4***
Third Party	217	44	8	0	36	10
Corrosion	165	12	17	0	12	1
Miscellaneous	120	0	1	0	32	0
Incorrect Op	57	4	6	0	58	0
Weather	43	0	0	0	0	0
Unknown	46	10	2	0	8	4
Manufacturing Related	31	8	0	0	0	1
Weld/Fab	31	0	0	0	4	0
Outside Force	20	2	0	0	1	0
Environment	12	0	0	0	0	0
Total	742	80	34	0	151	16

All Interstate Transmission Line Pipe

All number reflect 1985 – 7/2000 incidents plus the Carlsbad accident.

*Approximately 10% of all transmission line piping is in Class 3 & 4 locations. This percentage is based upon data received this year from the pipeline companies.

Section 3 - Pipeline Threats and Impacts

Gas pipeline incident data has been analyzed by PRCI (Pipeline Research Council International) to permit evaluation of industry trends to provide guidance for the direction of research efforts to improve pipeline safety and reliability. In order to provide for improved clarity and accuracy, the more recent data analyses by Kiefner & Associates (Ref. 2) have been based on 22 incident causes developed from their data analysis efforts. The causes were selected by Kiefner with input from pipeline operating personnel and GRI. This provided for an improved basis for root cause analysis and incident classification.

For the purposes of this report and matrix construction, Kiefner's 22 incident causes have been grouped into the following 10 major categories. Each category contains one or more incident causes.

- **Third Party Damage**
  - Third party inflicted damage (instantaneous/immediate fail)
  - Previously damaged pipe (delayed failure mode)
  - Vandalism
- **Corrosion Related**
  - External
  - Internal
- **Miscellaneous Equipment and Pipe**
  - Gasket O-ring failure
  - Stripped threads/broken pipe/coupling fail
  - Control/Relief equipment malfunction
  - Seal/pump packing failure
  - Wrinkle bend or buckle
  - Miscellaneous
- **Incorrect Operations**
  - Incorrect operation company procedure
- **Weather Related**
  - Cold weather
  - Lightning
  - Heavy rain or floods
- **Unknown**
- **Manufacturing Related Defects**
  - Defect pipe seam
  - Defective pipe
- **Welding/Fabrication Related**
  - Defective pipe girth weld
  - Defective fabrication weld
- **Outside Forces**
  - Earth movement
- **Environmental Cracking**
  - Stress corrosion cracking

The Third Party Damage category contains three of the 22 incident causes including third party inflicted damage (implied instantaneous failure), previously damaged pipe (implied delayed failure), and vandalism. The latter cause has been included in this group since some equipment damage or destruction may occur. Each of these causes results in a similar threat of pipeline damage and failure. The distinction between immediate and delayed failure modes is important since the possible prevention/detection and maintenance/mitigation practices available to a pipeline operator are significantly impacted. Additional data and discussion on delayed and immediate failures can be found in Ref. 2.

Two of the 22 incident causes, external and internal corrosion are included in the Corrosion Related category. In addition to the more typical conditions that promote internal corrosion such as moisture content, gas quality, and flow conditions, this also includes microbiologically induced corrosion (MIC). In this category, some of the prevention/detection and maintenance/mitigation practices can be used for both types of corrosion. However, some of the leading practices are unique to the particular incident cause.

The Miscellaneous Equipment and Pipe category contains 6 of the 22 incident causes including:

Gasket/ O-Ring Failure
Stripped threads/Broken pipe/Coupling failure
Control/Relief equipment malfunction
Seal/Pump packing failure
Wrinkle bend or buckle
Miscellaneous

Most of the gasket and O-Ring reported incidents were actually gasket and O-Ring failures. Others included pipeline mechanical couplings and valve seal leaks.

A majority of the incidents in the Stripped threads incident cause included pipeline mechanical coupling failures and failures of various threaded connections.

Control/Relief equipment incidents primarily included regulator failures, valve operator malfunctions, and turbine/compressor control failures.

The Miscellaneous equipment incident cause primarily includes other types of incidents that do not fit the other 21 incident cause descriptions. This mainly included compression equipment failures, failure of pipe components (i.e., valves, flanges), and bolts, plus other equipment such as tubing, gauges etc. that resulted in a gas release. Many of these failures occur inside compressor stations or processing plants.

The Incorrect Operations category applies to incorrect operations by operator personnel. A number of specific causes have been included but gas ignition by some electrical source or welding, ignition of other combustible materials, incorrect maintenance practices, and incorrect ILI (In-Line Inspection) procedures accounted for more than half of the incidents.

Weather Related incidents include 3 of the 22 incident causes including cold weather, lightning, and heavy rains or floods. Cold weather related incidents were mainly related to internal freeze-ups or ice plugs blocking flow, and frost heave.

The Unknown category is used for those incidents that are not easily identified with the other 21 causes. Further analysis may provide a clearer classification for analysis purposes.

Manufacturing Related Defects include 2 of the 22 incident causes including defective pipe seams and defective pipe. Defective pipe seam incidents primarily occurred in some manufacturer specific pre 1970 ERW (Electric Resistance Welded) and DSAW (Double Submerged Arc Welded) pipe.

The Welding/Fabrication Related category includes 2 of the 22 incident causes including defective pipe girth weld and defective fabrication weld. Defective pipe girth welds imply welding related defects in the circumferential welds made during pipeline construction or replacement. Defective fabrication welds include attachment of components or branch lines to a pipeline that may be done in-service. One of the main causes reported was making defect-free fillet welds for installation of saddles and steel sleeves. This type of welding is generally more difficult and requires highly skilled workers.

One of the 22 incident causes is contained in the Outside forces category which is Earth Movement. These events primarily consisted of landslides, subsidence, and unstable ROW areas.

The Environmental Cracking category contains one of the 22 incident causes called stress corrosion cracking. This incident cause includes external cracking on pipelines that require a particular combination of materials, stress levels, and electrochemical environments to be present.

It should be noted that the forthcoming OPS rule-making for high consequence areas concentrates on the line pipe where the public is exposed to the impacts of these threats. Pipeline company fenced-in property, such as compressor stations, etc., while posing threats to employees, usually do not impact the public and will not be part of the HCA rule-marking.

Section 4 - Comparison of Practices and Requirements

Using the 22 identified threats/causes and the incidence data available by each cause, the regulations were analyzed to determine which regulatory sections addressed which cause. Pipeline companies provided significant assistance in the evaluation of which practices they use to address each of the threats/causes. A study was performed to look at what has been and is being done in the R&D arena to further improve the industry's capabilities. Existing standards used by the industry to maintain integrity are also listed under the causes they mitigate most effectively. The result is the matrix shown in Table 4-1. The primary purpose of the matrix is to answer such questions as:

- are the regulations addressing the threats/causes of pipeline failures;
- are industry practices addressing these threats/causes;
- is existing R&D addressing the right issues,
- lastly, are these actions effective?

The left-hand column of the matrix titled "Causes of Failures" contains the incident causes listed in rank order by number of incidents. Third Party Damage has the most total incidents, Corrosion (internal and external) the second most numerous, etc.

In the column labeled "Impact", the total number of incidents, number of fatalities, and number of injuries has been tabulated. These data comprise a subset of the DOT reportable incident database and apply only to onshore, interstate gathering and transmission pipelines. (Ref. - Report GRI-00/0077). This information has been updated using the most recent available information in the DOT incident database including data tabulated to 7/2000. It also contains data from the recent Carlsbad pipeline incident that resulted in multiple fatalities. The property damage values provided are average values from statistical analysis of the DOT reported costs. Property damage impacts provided have been based on a statistical analysis of the reportable incident data. Some of the failure causes were found to a have a large cost variation. Property damage statistics should be used with discretion.

The "192 Requirements" column was developed through a detailed review of requirements in 49 CFR 192 and the potential impact of the required design, inspection, maintenance, or repair activity in mitigating the particular failure cause. This column has been subdivided into "Primary" and "Secondary" requirements since some sections of 49 CFR 192 have a primary or more direct application to particular failure cause while others have secondary or more indirect application. In addition to the summary of the 49 CFR 192 requirements shown in this column, a more detailed tabulation was completed. The results of this review are provided in Appendix A.

Results of these reviews showed that for the 22 incident causes, 49 CFR 192 currently has considerable primary and/or secondary coverage for each cause.

While only 49 CFR 192 requirements have been included in the matrix, it is also recognized that OSHA safety, NRC radiation safety, NFPA (combustible liquids and electrical) plus other regulations, also impact the pipeline industry. Additional API, ASME/ANSI, and ASTM codes and standards including ASME/ANSI B31.8 have been incorporated by reference in 49 CFR 192.

Three columns of information have been included in the "Leading Industry Practices" column including the leading industry prevention, detection and mitigation activities, frequency of use, and extent of application in an operators pipeline system. The "Practices" list only includes activities used by pipeline operators and not those that may be employed on an experimental or trial basis or others that would be considered as emerging technology. This list was compiled with significant assistance and input from individuals representing a number of pipeline companies whose operations represent the majority of the total transmission pipeline mileage in the US.

Many of these practices are used individually or in various combinations with others. For instance, there have been efforts to correlate the results of close interval surveys (CIS) with in-line inspection (ILI) tool runs in order to maximize the pipeline integrity information obtained. Others have supplemented CIS with localized direct current voltage gradient (DCVG) analysis to gain additional information about the nature of CIS anomalies thereby focussing maintenance mitigation action. Since numerous combinations of practices are being used by various pipeline operators, no attempt has been made to describe this within the matrix but such combination efforts constitute a less structured form of direct assessment and provide excellent background for the companion direct assessment (DA) effort. Still others have implemented somewhat unique methods such as establishing a contractor database to identify repeat offenders and rewards for reports of encroachment.

While the matrix includes many significant prevention, detection, maintenance, and mitigation methods applied by pipeline operators, it was again made clear during this effort that one of the most powerful and useful failure prevention methods is public education. Each company educates the public and contractors both locally and along the pipeline ROW's. Other programs, including Dig Safely and Common Ground, are examples of other efforts in the public safety and education arena. (Ref. 4)

The Common Ground Initiative has been included at the top of the "Practices" column in the Third Party Damage Category since it represents a significant effort aimed at identification and validation of best practices for preventing damage to various types of underground facilities. For third party damage, this report offers useful information to pipeline operators and is the principal guide for leading practices listed in this category.

With respect to the "192 Requirements" and "Leading Industry Practices" columns, it should be pointed out that reference to Section 192.617, Investigation of Failures, has not been included in the matrix since it is directly applicable to all 22 incident causes. A corollary to this regulation that belongs in the practices column was root cause analysis. This was considered to be a necessary practice for all incident types. Root cause analysis is an effective prevention method of a good integrity management program that requires that the actual causes of an incident be clearly identified thereby minimizing the chance of recurrence. Pipeline companies actively use it.

In the “Frequency” column, the frequencies of the application for the leading practices listed were solicited to estimate the typical overall range representing current industry practice. Application frequencies ranged from the minimum intervals stipulated by 49 CFR 192 to increasing frequencies. It is well known that many pipeline operators have been implementing risk-based prevention, detection, and maintenance frequencies. This methodology has been gaining momentum which has been amplified in the matrix that shows a significant number of “risk based” frequencies. The risk based methods also range widely from simpler knowledge based risk assessment practices to more sophisticated model or scenario based approaches. Some are using even more advanced absolute or probabilistic risk models. With these methods and the pipeline integrity knowledge gained in the process, pipeline operators are able to evaluate failure probabilities and loss consequences thereby tuning resource allocation to improving safety/reliability. (Ref. 5 - GRI-95/0228.1,2,3,4 - Risk Management Vol. 1-4). Frequency of application varies between companies and between pipeline segments within a company.

Individuals involved in the gas pipeline industry have been developing and improving standards for the design, construction, operation and maintenance of gas pipelines for more than 50 years. Standards developing organizations such as ASME, NACE, NFPA, AWS, etc., using recognized ANSI consensus standards processes have developed standards, some of which are incorporated by reference into the 192 regulations. The matrix lists those standards, recommended practices and guidelines that most directly affect each of the 22 causes and are used by leading companies.

Standards presently under development are also listed.

The gas transmission pipeline industry has invested $100MM over the past 5 years to develop improved prevention, detection, and mitigation tools and methods to improve an already outstanding safety record. The “Applicable R&D” column at the right side of the matrix lists a brief “snapshot” of some the work directly addressing each of the 22 incident causes. It is not intended to provide a comprehensive reference for such work but to provide an indication of the subject matter and the organizations conducting it. This included both domestic and foreign organizations involved. Significant domestic sources are the PRCI and GRI that have conducted relevant industry research since 1952. Research and methods developed by foreign organizations such as the EPRG (European Pipeline Research Group) are also an important source of improved methods and pipeline technology. A more complete listing of relevant R&D by cause is given in Appendix C.

Additional discussion concerning the leading prevention/detection practices and mitigation/repair practices is provided in the next two chapters of this report.

-

Table 4-1

Gas Transmission Pipelines Leading Detection, Prevention and Mitigation Practices and Relevant R&D								
Cause of Failures	**Impact**	**192 Requirements**		**Leading Industry Practice**				
	No./Fatal/Inj Property Damage $	**Primary (1)**	**Secondary (1)**	**Practice**	**Frequency**	**Extent**	**Applicable Standards, Practices, Guidelines**	**Applicable R&D**
Third Party Damage				**Common Ground Initiative**				
• Third party inflicted damage – TP (Instantan-eous/ immediate	187 / 8 / 32 $110K	103-(Gen. Design) 111-(Design factor) 317-(Hazard prot) 327-(Cover) 614-(Dam. Prevent) 616-(Public educat) 705-(Patrol) 707-(Line markers) 713-(Repair)	615 –(Emerg Plan)	One call system Increased cover depth Increased line marker frequency Protective barriers/ coatings Increased patrol frequency Pipe replacement Line relocation Public awareness/education Marker tape at top of pipe Repeat offender database Reward for report of encroachment	Per CFR Per CFR/As needed Per CFR/Risk based Per CFR/Risk based Per CFR/Risk based As needed As needed Per CFR/Risk based Risk based As needed/risk based All areas	All areas Affected areas Higher risk areas Affected areas Higher risk areas All areas Affected areas All areas All areas System-wide System-wide	ASME B31.8 ASME (Future Dent/Gouge)	**Real-Time Monitoring to Detect Third-Party Damage** Gas Research Institute, Report No. 96/007 **EPRG Recommendations for the Assessment of the Tolerance and Resistance of Pipelines to External Damage** Paper No. 21, PRCI-EPRG 11th Joint Technical Meeting (April 1997) **The Pipe-Agression Rig: A Comprehensive Means for Studying Pipe Resistance to Third Party Damage** Paper No. 22, PRCI-EPRG 11th Joint Technical Meeting (April 1997) **Effectiveness of Various Means of Detecting Third Party Damage** GRI-99/0050 **Common Ground: Study of One-Call Systems and Damage Prevention Best Practices** June 1999 (www.dot.gov)
• Previously damaged pipe – PDP (Delayed failure mode)	25 / 0 / 4 $375K	65-(Pipe transp) 103-(Gen. Design) 111-(Design factor) 305-(Insp-Gen) 307-(Const insp) 309-(Const repair) 317-(Hazard prot) 327-(Cover) 613-(Surveil) * 614-(Dam. Prevent) 616-(Public educat) 705-(Patrol) 706-(Leak survey) 707-(Line markers) 313-(Bends) 503-(Test Req)	615-(Emerg Plan)	One call system Pipe manufacturing inspection Pipe loading / transport inspection Construction inspection Coating integrity evaluation (DCVG etc) ILI/ Geometry tool eval Hydrotest (pre-service) Hydrotest (periodic retest) CIS Pipe replacement Grind repair Epoxy filled steel/ Composite sleeve Direct deposition weld repair Protective coatings Public awareness/ education Marker tape at top of pipe Repeat offender database Increased line marker frequency Increased patrol frequency Reward for report of encroachment	Per CFR As needed during prod. Per CFR/As needed Per CFR Risk based Risk based Per CFR Retest in X yrs/Risk based Risk based sched As needed As needed As needed As needed Risk based Per CFR/Risk based Risk based As needed/Risk based Per CFR/Risk Based Per CFR/Risk Based All areas	All areas All new pipe prod All pipe Replacement/new const All areas High risk/all areas (ILI currently develop) All areas All areas All areas in 10 yrs All areas All areas All areas All areas All areas All areas All areas System-wide Higher risk areas Higher risk areas System-wide	ASME B31.8 API 1156 NACE (Future LIL Std-RP212) ASME (Future Hydrotest Std.) ASME (Future Dent/Gouge)	**Repair of Line Pipe with Dents and Scratches** PRCI – PR-218-9508 **Cyclic Pressure Fatigue Life of Pipelines with Plain Dents, Dents with Gouges, and Dents with Welds (Volume A)** PRCI – PR-201-9324 **Guidelines for the Assessment of Dents on Welds** PRCI – PR-218-9822 **In-Line Inspection Technologies for Mechanical Damage and SCC in Pipelines-Final Report on Tasks 1 and 2** No. DTRS56-96-C-0010 (1998) **EPRG Recommendations for the Assessment of the Tolerance and Resistance of Pipelines to External Damage** No. 21, PRCI-EPRG 11th Joint Technical Meeting (April 1997) **Magnetic Flux Leakage (MFL) Technology for Natural Gas Pipelines** GRI-99______

Gas Transmission Pipelines
Leading Detection, Prevention and Mitigation Practices and Relevant R&D

Cause of Failures	Impact	192 Requirements		Leading Industry Practice				
	No./Fatal/Inj Property Damage $	Primary (1)	Secondary (1)	Practice	Frequency	Extent	Applicable Standards, Practices, Guidelines	Applicable R&D
*See Appendix A – Pages A-33 to A-35								
Third Party Damage (Continued)								
• Vandalism – V	5 / 0 / 0 $40K	163-(Comp Stat Design) 179- (Valve prot) 317-(Hazard prot) 327-(Cover) 613-(Surveil) 614-(Dam. Prevent) 705-(Patrol) 713-(Repair)	615-(Emerg plan)	Increased patrol frequency External protection (fencing etc) Increased leak survey Visual / Bellhole inspection Signs / Markers Reward for reporting an event Alarm input to SCADA system ILI	As needed/High risk As needed/High risk As needed/High risk Per CFR All areas All areas As needed As needed/Risk based	Selected areas Selected areas Selected areas Entire system Entire system Entire system Selected areas Developmental	ASME B31.8 NACE (future LIL Std-RP212) ASME (Future Hydrotest Std.) ASME (Future Dent/Gouge)	**Real-Time Monitoring to Detect Third-Party Damage** GRI - No. 96/0077
Corrosion Related								
• External – EC	90 / 5 / 8 $222K	150-(ILI Passage) 455-(Gen. Post 1971) 457-(Gen. Pre-1971) 459-(Examination) 461-(Ext. coating) 463-(CP) 465-(Monitoring) 467-(Elect isolation) 469-Test stations) 471-(Test leads) 473-(Interference) 479-(Atmospheric) 481-(Atmospheric) 485-(Remedial) 705-(Leak survey) 706-(Patrol) 711-(Repair-Gen) 713-(Perm repair) 715-(Weld repair)	603-(Gen Oper) 613-(Surveil)	ILI tool run Hydrostatic re-test Reduced operating pressure CIS/DCVG survey Upgrade CP coverage ECA (B31G/RSTRENG) evaluation Rehabilitation (Inspect/ Re-coat) Bellhole/ visual inspection Soil corrosivity evaluation (inc. MIC) Apply rate predictive methods Buried coupon monitoring Apply protective coating (above ground) Pipe replacement Mechanical clamp Pressurized sleeve (pumpkin) Composite sleeve repair Direct weld deposition Resistivity Survey	Risk based/10 yrs Risk based As needed/Risk based Per CFR/As reqd by test point data As needed Risk based Risk based/ Risk based/ Risk based/ As needed/Risk based Per CFR/As needed Per CFR/As needed Per CFR/As needed Per CFR/As needed Per CFR Per CFR As needed	All areas Affected areas Affected areas Affected areas Affected areas Affected areas Affected areas Problem areas All areas Existing/potential prob. areas + new const. Above ground pipe Affected areas Affected areas Affected areas All areas All Areas All areas	ASME B31.8 ASME B31G RSTRENG (PRCI PR 3-805) NACE RP0169 NACE RP0274 NACE RP0275 NACE RP0177 NACE RP0286 NACE RP0572 NACE RP0190 NACE RP0394 NACE TM0497 API 579 NACE (Future Monitoring Std.) NACE (Future MIC Std.) NACE (Future LIL Std-RP212) ASME (Future Hydrotest Std.)	**External Corrosion Control Monitoring Practices (Vol. I & II)** PRCI – PR-186-9610 **Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe** (RSTRENG) PRCI – PR-3-805 **Evaluation of Circumferential Magnetic Flux for In-Line Detection of Stress Corrosion Cracks and Selective Seam Weld Corrosion** PRCI – PR-3-9420 **Use of In-line Inspection Data for Integrity Management** Paper No. 547, Corrosion 99

Gas Transmission Pipelines
Leading Detection, Prevention and Mitigation Practices and Relevant R&D

Cause of Failures	Impact	192 Requirements		Leading Industry Practice				
	No./Fatal/Inj Property Damage $	Primary (1)	Secondary (1)	Practice	Frequency	Extent	Applicable Standards, Practices, Guidelines	Applicable R&D
Corrosion Related (Continued)								
• Internal-IC	75 / 12 / 4 $175K	475-(Gen IC) 477-(IC monitoring) 485-(Remedial) 705-(Patrol) 706-(Leak survey) 150-(ILI Passage)	53(a)-(Materials) 603-(Gen Oper) 613-(Surveil)	ILI tool run Hydrostatic retest ECA (B31G/RSTRENG) Gas moisture reduction (separators) Biocide injection Inhibitor injection Internal coupon monitoring Gas quality control MIC testing External UT exam (B-scan) Pipe replacement Iron analysis Cleaning pig run Internal corrosion coating Remove or modify drips CRA materials Radiography	Risk based/10 years Risk based/ X years Per CFR/as needed As needed As needed As needed Per CFR Per CFR/As needed Per CFR/As needed As needed Per CFR/As needed As needed Daily-Annual As needed Risk based/As needed As needed As needed	All areas Affected areas Affected areas of system All areas Affected areas Affected areas Affected areas All areas All areas Affected areas Affected areas Affected areas Affected areas of system Affected areas Affected drip barrels Flow lines Affected areas	ASME B31.8 NACE MR0175 NACE TM0194 ASME B31G RSTRENG 9PRCI PR 3-805) NACE (Future Int. Corr. Std.)	**Effects of Water Chemistry on Internal Corrosion of Steel Pipelines** PRCI – PR-15-9712 **Evaluation of Circumferential Magnetic Flux for In-Line Detection of Stress Corrosion Cracks and Selective Seam Weld Corrosion** PRCI – PR-3-9420 **Examination of External Weld Deposition Repair for Internal Wall Loss** PRCI – PR-185-9633 **Quantitative Corrosion Risk Assessment Based on Pig Data** NACE/96
Miscellaneous Equipment and Pipe								

Gas Transmission Pipelines
Leading Detection, Prevention and Mitigation Practices and Relevant R&D

Cause of Failures	Impact	192 Requirements		Leading Industry Practice				
	No./Fatal/Inj Property Damage $	Primary (1)	Secondary (1)	Practice	Frequency	Extent	Applicable Standards, Practices, Guidelines	Applicable R&D
• Gasket O-ring failure – GF	6 / 0 / 2 $1.2MM	53(a)-(Matls) 273-(Gen joining) 605-(Procedures) 613-(Cont'd surveill) 706-(Leak survey)	736-(Gas detect) 749-((Vault maint) 751-(Accid. ignit)	Materials evaluation/ selection Use appropriate install procedure Conduct I/M training (Formal/OJT) Operator procedure compliance audits Apply proper bolt tension Leak inspections Installation QA/QC	Service conditions/reliability Per mfgr/Operator procedure Per CFR/Operator require Audit schedule/As reqd. All installations Per CFR As needed	All equipment All areas All areas All areas All areas All areas All areas	ASME B16.20 ASME B16.21	**Cost Effective Leak Mitigation at Natural Gas Transmission Compressor Stations** PRCI – PR-246-9526
Miscellaneous Equipment and Pipe								
• Stripped threads/ broken pipe/coupling fail – TSBPC	19/ 0 / 7 $850K	53(a)-(Matls) 103-(Design-Pipe) 143-(Design-Gen Req) 605-(Procedures) 273-(Joining – Gen)	751-(Accid. ignit)	Design considerations Proper construction methods Testing considerations Fabrication QA/QC Control piping vibration Maintenance of coupled pipe Leakage evaluation (patrol) Materials evaluation/selection Use appropriate install procedure Conduct I/M training (Formal/OJT)	Per CFR/Operation cond Per CFR/Operation cond Appropriate test procedure As needed As needed Per CFR Per CFR/Oper procedure Service cond/reliability Per CFR/Oper procedure Per CFR/Operator require	All areas All areas All areas All areas Compressor stations All coupled lines All areas All equipment All areas All areas	API 579 ASME B31.8	
• Control/ Relief equipment malfunction – MCRE	24 / 1 / 3 $221K	53(a)-(Matls) 143-(Design-Gen Req) 169-(Pres limit device) 199-(Pres rel design) 706-(Leak survey) 731-(Insp/test at CS) 739-(Insp/test–Regs) 741-(Insp/test-Gauge) 743-(Test relief dev)	605-(Procedures) 736-(Gas detect) 751-(Accid. ignit)	Proper design for application Proper installation/maint procedures Proper materials/ equipment specs Proper test procedures Conduct I/M training (Formal/OJT) Internal compliance audits	Per CFR+ Per CFR Per CFR+ Per CFR Per CFR Per schedule/ As needed	All facilities All facilities All facilities All facilities All facilities All facilities	ASME B31.8 ASME PTC 25	**Fiber Optic Pressure Sensor Development** PRCI – PR-219-9225 **Field Application of Electronic Gas Admission with Cylinder Pressure Feedback for large Bore Engines** PRCI – PR-239-9438

Gas Transmission Pipelines
Leading Detection, Prevention and Mitigation Practices and Relevant R&D

Cause of Failures	Impact	192 Requirements		Leading Industry Practice				
	No./Fatal/Inj Property Damage $	Primary (1)	Secondary (1)	Practice	Frequency	Extent	Applicable Standards, Practices, Guidelines	Applicable R&D
• Seal/pump packing failure – SPPF	4 / 0 / 2 N/D	53(a)-(Matls) 273-(Gen joining) 257-(Meter install) 605-(Procedures) 706-((Leak survey)	167-(Comp ESD) 171-(Comp addnl safety) 736)-(Gas detect) 751-(Accid. ignit)	Proper installation/maint procedures Proper materials/ equipment specs Proper test procedures Conduct I/M training (Formal/OJT) Internal compliance audits	Per CFR Per CFR+ Per CFR Per CFR Per schedule/ As needed	All facilities All facilities All facilities All facilities All facilities		**Cost Effective Leak Mitigation at Natural Gas Transmission Compressor Stations** PRCI – PR-246-9526
Miscellan-eous Equip-ment and Pipe								
• Wrinkle bend or buckle – WBB	6 / 0 / 0 $160K	159-(Flexibility) 161-((Anchors/suppl) 315-(Wrinkle bends) 317-(Hazard prot)	605-(Procedures) 706-(Leak survey)	Control pressure/cyclic stress Remove from pipeline ECA evaluation Geometry tool run Strain monitoring	As needed When discovered As needed Location of wrinkles As needed	Lines with previous wrinkle problems All facilities Developmental process Affected facilities Affected facilities	ASME B31.8	**High-Accuracy Caliper Surveys with the 'Geopig' Pipeline Internal Geometry Tool,** ***Pipeline Pigging and Inspection Technology Conference*** 1991

Gas Transmission Pipelines Leading Detection, Prevention and Mitigation Practices and Relevant R&D								
Cause of Failures	**Impact**	**192 Requirements**		**Leading Industry Practice**				
	No./Fatal/Inj Property Damage $	**Primary (1)**	**Secondary (1)**	**Practice**	**Frequency**	**Extent**	**Applicable Standards, Practices, Guidelines**	**Applicable R&D**
• Mis-cellaneous – MISC	61 / 0 / 18 $815K	-	605-(Procedures)	Refer to other incident causes			MSS SP-44 MSS SP-75 MSS SP-6 MSS SP-25 API 6D ASME B31.3 ASME Section VIII ASME Section V ASME B16.5 ASME B16.9 ASME B16.11 ASTM A193 ASTM A194 AWS D1.1 NFPA 30 ANSI/NFPA 58 ANSI/NFPA 59 ANSI/NFPA 70	**Recommended Practice for Sour-Service Piping Components** PRCI – PR-252-9605 **Design Guidelines for High-Strength Pipe Fittings** PRCI – PR-201-9320 **GRI Pipeline Simulation Facility Pull Rig** GRI 94/0377
Incorrect Operation								
• Incorrect operation Company procedure – IO	57 / 6 / 58 $350K	199-(Pres relief design) 605-(Procedures) 615-(Emerg plan) 805-(Qualification)	751-(Accid. ignit)	Develop/Improve Company procedures Improved design criteria Operational review/critiques Proper materials application Equipment/component specs Training – (Formal/OJT) Internal compliance audits	Annual per CFR/ As needed As needed As needed Per CFR Most pipe/comp Per CFR Per schedule/ As needed	All facilities All facilities All significant events/incidents All facilities All facilities All facilities All facilties	ASME B31.8	**State of the Art Intelligent Control for Large Engines** PRCI – PR-179-9131 **Reliability Based Planning of Inspection & Maintenance** PRCI – PR-224-9519 **Relative Risk – The Competitive Advantage** International Pipeline Conference – Volume I, ASME (1998)
Weather Related								

Gas Transmission Pipelines
Leading Detection, Prevention and Mitigation Practices and Relevant R&D

Cause of Failures	Impact	192 Requirements		Leading Industry Practice				
	No./Fatal/Inj Property Damage $	Primary (1)	Secondary (1)	Practice	Frequency	Extent	Applicable Standards, Practices, Guidelines	Applicable R&D
• Cold Weather – CW	6 / 0 / 0 $73K	53(a)-(Matls.) App-A-(Ref Specs)	141-(Pipe Design) 159-(Flexibility) 225-(Gen. Weldings) 303-(Spec. Comp) 605-(Proced. Manual) 615-((Emerg Plan)	Appropriate facility design/const methods Materials testing/ characterization ECA applications Indirect gas heating Frozen valve thaw Methanol injection (hydrates) Heat trace Frost heave mitigation Catalytic heaters Specific coating materials applied Low temp operational procedures	All projects Per CFR As needed As needed As needed As needed As needed As needed As needed As needed All facilities	New facility All facilities All facilities Northern climates All facilities All facilities All above grade Northern climates All above grade Above/below transit Northern climates	ASTM A333 ASME B31.8 ASME Section VIII ASME B31.3	
• Lightning-LIGHT	8 / 0 / 0 $182K	467-(Elect. isol) 65-(CP monitor)	605-(Proceed Manual) 613-(Contd surveill) 615-(Emerg plan) 713-(Repair)	Rectifier protection Rectifier design considerations Evaluate rectifier grounding Special grounding system design Grounding cells Lightning dissipation Insulating joints Periodic rectifier insp	Per CFR or risk based As needed Per CFR As needed Specific locations As needed Per CFR Per CFR	All facil. Problem areas more frequent All facilities All facilities. More Freq in high incid area Allfacilities All facilities Comp/Meter stations All facilities All facilities	ASME B31.8 NACE RP0177	
• Heavy rain or floods – HRF	29 / 0 / 0 $700K	103-(Gen Design) 159-(Flexibility) 179-(Trans valves) 189-(Vaults) 317-(Hazard prot.) 327-(Cover) 705-(Patrol)	303-(Spec comply) 605-(Proced. manual) 613-(Cont surveill) 615-(Emerg plan) 751-(Accid ignit) 713-(Repair)	Pipeline isolation River bottom survey Underwater coating (in place) Lowering pipe (burial depth increase) Erosion control(mats, wiers, rip rap) Crossing design Directional drilling Weight coating Restraints/anchors Increased wall thickness	As required 1-5 years for major Rivers/critical areas Also risk based freq As needed As needed As needed All projects As needed As needed As needed As needed	Flood plain; river Erosion prone or navigable waterway All water crossings Erosion prone or Navigable waterway Erosion prone areas Erosion prone or Navigable waterway Environmental/ high Scour areas	ASME B31.8	**Integrity Assessment of Exposed/Unburied Pipe in River** PRCI – PR-170-9520 **Satellite Radar Interferometry to Detect and Characterize Slope Motion Hazardous to Gas Pipelines** GRI-99/0096

Gas Transmission Pipelines
Leading Detection, Prevention and Mitigation Practices and Relevant R&D

Cause of Failures	Impact	192 Requirements		Leading Industry Practice				
	No./Fatal/Inj Property Damage $	Primary [1]	Secondary [1]	Practice	Frequency	Extent	Applicable Standards, Practices, Guidelines	Applicable R&D
Unknown	46 / 2 / 8		605-(Procedures)	Refer to criteria for other groups.			See other causes	
Manufac-turing Related Defects								
• Defect pipe seam – DPS	20 / 0 / 0 $470K	53(a)-(Matls) App A-(Specs) 55-(Steel pipe) 113-(Joint factor) 503-(Test Req) 713-(Perm repair of imperfections) 715-(Perm repair of welds) 717-(Perm repair of leaks)	313-(Bends/elbows) 605-(Procedures) 706-(Leak survey)	Company pipe specifications Production QA/QC Hydrotest Pipe mfg. Selection Sleeve repair Replacement ECA evaluation	As needed As needed Per CFR As needed Per CFR Per CFR As needed	All new const All new const. Entire system All pipe purchased Entire system Entire system Entire system	API Specification 5L API RP 5L1 API RP 5L5 ASTM A53 ASTM A106 ASTM A333 ASTM A372 ASTM A381 ASTM A671 ASTM A672 ASTM A691 ASNT RP NST-TC-1A	**Investigation of Sulfide-Stress Cracking at Pipe Seam Welds** PRCI – Report 184 **Seam-Weld Quality of Modern ERW/HFI Pipe** PRCI – Report 198 (NG18 – Report 184) **A Breakthrough in the Detection of Long Seam Weld Defects in Steel Pipelines** Pipeline Integrity International, 1999
• Defective pipe – DP	11 / 0 / 0 $360K	53(a)-(Matls) App A-(Specs) 55-(Steel pipe) 309-(Steel pipe repair) 503-(Test Req) 713-(Perm repair of imperfections) 715-(Perm repair of welds) 717-(Perm repair of leaks) 103-(Gen Pipe Design) 150-(ILI Passage)	605-(Procedures) 706-(Leak survey)	Company pipe specifications Production QA/QC Hydrotest Pipe mfgr selection Sleeve repair Replacement ECA evaluation Composite sleeve repair	As needed As needed Per CFR As needed Per CFR Per CFR As needed As applicable	All new const. All new const. Entire system All pipe purchased Entire system Entire system Entire system Entire system	API Specification 5L API RP 5L1 API RP 5L5 API RP 5L6 API RP 5LW ASTM A53 ASTM A106 ASTM A333 ASTM A372 ASTM A381 ASTM A671 ASTM A672 ASTM A691 ASTM D2513 ASTM D2517 API 579 BS 7910	**Development and Validation Ductile Flaw Growth Analysis** PRCI – Report 193 **Hydrotest Strategies for Gas Transmission Pipelines – Ductile Flaw** PRCI – Report 194 **High Pressure Pipe Design** PRCI – PR-201-9202 **History of Line Pipe Manufacturing in North America** ASME Research Report CRTD-Vol. 43, Book Number 100396

Gas Transmission Pipelines Leading Detection, Prevention and Mitigation Practices and Relevant R&D								
Cause of Failures	**Impact**	**192 Requirements**		**Leading Industry Practice**				
	No./Fatal/Inj Property Damage $	**Primary [(1)]**	**Secondary [(1)]**	**Practice**	**Frequency**	**Extent**	**Applicable Standards, Practices, Guidelines**	**Applicable R&D**
Welding/ Fabrication Related								
• Defective pipe girth weld – DGW	17 / 0 / 0 $90K	225-(Welding-Gen) 227-(Welder qual) 229-(Welder-Limits) 231-(Weather prot) 233-(Miter joints) 235-(Weld prepare) 241-(Insp/test welds) 243-(Weld NDT) 245-(Weld defect rem) 309-(Steel pipe repair) 503-(Test Req.) 715-(Weld repair) 805-(Qualif program)	605-(Procedures) 706-(Leak survey) 751-(Accid. ignit)	Welding procedure selection Welding procedure qualification Field QA/QC Hydrotest Leak testing Welder qualification Welder/Inspector training Weld repair Weld replacement Sleeve repair Internal compliance audit Defect removal by grinding/NDE ECA evaluation	Per design requirement Per CFR As needed Per CFR Per CFR Per CFR Per CFR Per CFR Per CFR Per CFR As required Per CFR As needed	All facilities All facilities Active projects All facilities All facilities All facilities All involved indiv. All facilities All facilities All facilities All facilities All facilities Affected areas	API Standard 1104 ASME Section IX ASME Section II, Part C ASNT TC 1A ASME B31.8 API 579 BS 7910 AWS A5.x Series AWS CWI Certification	**Evaluation of Ultrasonic Technology for Volumetric Weld Inspection of Pipeline Girth Welds** PRCI – PR-220-9437 **Evaluation of Low Hydrogen Welding Processes for Pipeline Construction in High Strength Steel** PRCI – PR-164-9330 **Reliability-Based fitness for Service Assessment of Welds** PRCI – PR-185-9429 **Study of Processes for Welding Pipelines** PRCI – PR-164-007

Gas Transmission Pipelines
Leading Detection, Prevention and Mitigation Practices and Relevant R&D

Cause of Failures	Impact	192 Requirements		Leading Industry Practice				
	No./Fatal/Inj Property Damage $	Primary (1)	Secondary (1)	Practice	Frequency	Extent	Applicable Standards, Practices, Guidelines	Applicable R&D
• Defective fabrication weld – DFW	14 / 0 / 4 $590K	143-(Design-Gen Req) 151-(Tapping) 153-(Fab. component) 155-(Branch connect) 225-(Welding-Gen) 227-(Welder qual) 229-(Welder limits) 231-(Weather prot) 233-(Miterjoints) 235-(Weld prepare) 241-(Insp/test welds) 243-(Weld NDT) 245-(Weld defect rem) 309-(Steel pipe repair) 503-(Test req) 715-(Weld repair) 805-(Qualif. Program)	605-(Procedures) 706-(Leak survey) 751-(Accid. ignit)	Welding procedure selection Welding procedure qualification Field/Shop QA/QC Hydrotest Leak testing Welder qualification Welder/Inspector training Weld repair Weld replacement Internal compliance audit Defect removal by grinding/NDE Design/stress analysis ECA evaluation	Per design req. Per CFR As needed Per CFR Per CFR Per CFR Per CFR Per CFR Per CFR As required Per CFR As needed As needed	All facilities All facilities Active shop/ project All facilities All facilities All personnel All involved indiv All facilities All facilities All facilities All facilities Affected areas Affected areas	API Standard 1104 ASME Section IX ASME Section II, Part C API Standard 1107 ASNT TC 1A ASME B31.8 API 579 BS 7910 AWS D1.1 AWS A5.x Series AWS CWI Certification	**Pipeline In-Service Repair Manual** PRCI – PR-218-9307 **Fitness-for-Purpose Assessment Procedures for Sleeve Welds in Pipelines** PRCI – PR-185-014 **Guidelines for Weld Deposition Repair on Pipelines** PRCI – PR-185-9734
Outside Forces								

Gas Transmission Pipelines Leading Detection, Prevention and Mitigation Practices and Relevant R&D								
Cause of Failures	**Impact**	**192 Requirements**		**Leading Industry Practice**				
	No./Fatal/Inj Property Damage $	**Primary (1)**	**Secondary (1)**	**Practice**	**Frequency**	**Extent**	**Applicable Standards, Practices, Guidelines**	**Applicable R&D**
• Earth movement – EM	20 / 0 / 1 $435K	103-(Gen Design) 159-((Flexibility) 161-(Support/anchor) 317-(Hazard prot) 613-(Surveil) 614-(Dam. prevent) 705-(Patrol) 706-(Leak survey)	53(a)-(Matls) 603-(Gen Oper) 605-(Proced. manual)	Design issues (earthquake etc) Slope restoration Pipe strain monitoring Backfill removal for strain reduction Reduce pressure/isolate affected section Ground displacement surveys Increased patrol/surveillance Bellhole/ visual inspection Geometry/ pipe deformation tool run Cooperative effort with mining operators Relocate/Replace	As reqd by local geology As needed As needed As needed As needed As needed Per CFR/As needed As needed Before/After event As needed for predictive mitigation planning As needed	Affected areas Affected areas Affected areas Affected areas Affected areas Affected areas Affected areas Affected areas Affected areas Affected areas Affected areas	ASME B31.8	**Non-Conventional Means for Monitoring Pipelines in Areas of Soil Subsidence or Soil Movement** PRCI – Report 166 **Fiber Optic Strain Monitoring of Pipelines** PRCI – PR-255-9616 **Users Manual for CISPM-Comprehensive and Integrated Subsidence Prediction Model"** West Virginia University **Satellite Radar Interferometry to Detect and Characterize Slope Motion Hazardous to Gas Pipelines** GRI-99/0096
Environ-mental Cracking								
• Stress Corrosion Cracking – SCC	9 / 0 / 0 $315K	459-(Corr exam) 461-(Ext. corr)	53(a)-(Matls) 603-(Oper–Gen) 605-(Proced. manual) 713-(Repair)	Coating integrity evaluation (DCVG) Control applied CP range Control R-value/ stress level Pipe replacement Bellhole- Visual/ Surface MPI CIS Rehabilitation (Inspect/ re-coat) Grind repair/ re-coat Temperature reduction Coating selection/ design consid ECA based remediation Hydro re-test(for SCC) Pipeline design considerations Soil survey/ characterization SCC predictive methods	Per CFR/Risk based As needed As needed As needed Risk based Per CFR/Risk based As needed As needed New const/ replacement Per CFR As needed Risk based to 10 yrs New const/ replacement To be determined Risk based	All areas Developmental Local areas All affected areas All affected areas All affected areas All affected areas Comp station discharge All new installations All affected areas All affected areas All areas System baseline (developmental) All areas	ASME B31.8 API 579 NACE (Future T10E7)	**Characterization of Axial Flaws in Pipelines, with a Focus on Stress Corrosion Cracking** PRCI – Report 212 **Failure Criterion for Stress-Corrosion Cracking in Pipelines** PRCI – PR-3-9407 **Stress Corrosion Cracking Life Prediction Model (SCCLPM) Version 1.0 User's Manual and Software** PRCI – Report 217 **Evaluation of Circumferential Magnetic Flux for In-Line Detection of Stress Corrosion Cracks and Selective Seam Weld Corrosion** PRCI – PR-3-9420

DETECTION, PREVENTION, MITIGATION MATRIX

Explanatory notes to the Table

1. The causes of pipeline failures are the 22 causes developed by John Kiefner et al for PRCI –(Ref. 2)

2. The impact includes the total number of incidents, the number of deaths and the number of injuries, for onshore interstate and regulated gathering pipelines, from GRI Report # GRI-00/0077 updated to include 1999 and 2000 data through 7/2000 and the Carlsbad incident. The property damage values are calculated averages per incident from the DOT reports. The reported values can have a large variation for certain causes of failure and should be used with discretion.

3. The 192 Requirements column lists the paragraphs of 49 CFR 192, the gas transmission pipeline DOT regulations, that require specific inspections, maintenance or repair activities that directly (Primary) or indirectly (Secondary), help to mitigate the listed cause. Appendix A provides a more complete explanation of the regulation paragraphs cited.

4. The leading practices column lists the possible activities that are actually used by the pipeline companies, including, where applicable, the extent of the pipeline to which they are applied and the frequency of use. The Leading Practices are used individually and in various combinations. It is not possible to show the combinations of practices because they vary by pipeline segments and pipeline companies.

5. The gas transmission pipeline industry has spent over $100MM in the past 5 years developing capabilities to improve safety. The R&D column lists some directly applicable R&D that has been performed for the failure causes listed. An industry report on R&D is attached as Appendix B. A more complete listing of issued reports for each cause is shown in Appendix C.

6. While this table lists specific detection, prevention and Mitigation methods applied by the industry, one of the most powerful and useful methods to prevent failures is PUBLIC EDUCATION. The Dig Safely and Common Ground programs are just 2 examples of what is being done. Each pipeline company also educates the public, contractors etc. both locally and along their pipelines.

DETAILED NOTES:

- Most pipeline companies now use risk-based methods to guide them in their operations. With either commercially available risk assessment models or in-house developed models, companies evaluate the probabilities and consequences of losses. To this they add their years of experience and knowledge about each of the pipeline segments, and then plot a course of action to provide the safest, most reliable operation possible.

- For bellhole inspections, some companies perform magnetic particle inspections on the surface of the exposed pipe to check for cracking.

- For Third Party Damage, one company is developing a database of repeat offender contractors.

- A good integrity management program requires that the actual cause of an incident be clearly identified in order to prevent reoccurrence where possible. A leading practice among the pipeline companies is “root cause” analysis, determining the underlying cause or causes for a failure. This methodology is applied for most of the 22 causes of failures and is in and of itself, a prevention method.

- A definitive discussion of paragraph 192.613 is located in Appendix A, pages A-33 to A-35. It describes how the industry applies this paragraph in practice and how the intent of implementation of paragraph 192.613 is in essence an "Integrity Management" program.

Section 5 - Regulatory Requirements to Address Threats

Current interstate gas pipeline regulatory requirements contained in 49 CFR 192 have been derived from extensive industry initiatives dating back to the 1920's. This evolved from a general Standard that included gas piping published in 1935 to the ASA B31.1.8 Gas Transmission and Distribution Piping Systems Code document published in 1955. All state agencies with pipeline regulatory authority as well as many foreign countries adopted the 1958 revision, ASA B31.8. A major objective of those involved in formulating this Code was to provide a well founded set of pipeline design, construction, operation, and maintenance practices thereby minimizing the frequency of failures and improvement of public safety. (Ref. 6 - GRI 98/0367)

Federal authority to regulate interstate transmission pipelines was established in 1968 with passage of the Natural Gas Pipeline Safety Act in 1968 and the Office of Pipeline Safety was formed to administer it. The B31.8 Code was then adopted as the interim regulation until the Federal regulations (49 CFR 192) took effect in March 1971. ASME/ANSI B31.8, Gas Transmission and Distribution Piping Systems remains incorporated by reference in 49 CFR 192 and the B31.8 Committee continues its activity. Additional detail pertaining to the history and development of B31.8 are available in Ref. 6 - (GRI 98/0367)

The underlying principle in this background is that the industry and then the Federal regulations were, and are aimed at addressing public safety and mitigating threats to pipeline operations. Although 49 CFR 192 is the governing regulatory document, B31.8 is often used in conjunction with it to provide additional information. The provisions of the current version of 49 CFR 192, Subparts A-M with respect to their applicability to the 22-pipeline incident causes are discussed below. Additional detail concerning the regulatory requirements for each 49 CFR section included in the matrix has been provided in Appendix A.

Subpart A - General

This subpart mainly lays out the scope, definitions, and applicability of Part 192. It also contains several sections that impact pipeline threats. Section 192.7 (Incorporation by reference) references pipe transportation, construction, materials, fabrication, and corroded pipe analysis specifications listed in Appendix A that provide for minimum quality levels thereby reducing potential threats resulting from defective materials or fabrication. Material specifications also provide for more damage tolerant pipe and components that can reduce the consequences of third party damage. Class locations described in Section 192.5 affect the allowable design factor depending on population densities, thus taking incidence consequences into account. Test requirements are delineated that can also reduce the severity of third party damage and detect defective pipe.

Subpart B - Material

Subpart B contains requirement for general materials compatibility, qualification of steel pipe and components, plastic pipe, materials marking, and pipe transportation. This also references the listed specifications for new materials and required qualification and limitations for use of older or used steel pipe. These requirements, in addition to the materials marking criteria in 192.63, directly address the threat caused by installation of defective or improper pipe in a line. The pipe transportation criteria in 192.65 require compliance with API approved transportation of high diameter/thickness ratio pipe thereby addressing the previously damaged pipe issue. Several of the threats listed in the Miscellaneous Equipment and Pipe category are addressed by the compatibility criteria in 192.53.

Subpart C - Pipe Design

Pipe design requirements for steel, plastic, and copper materials are defined in this subpart. For steel pipe, it covers design pressure, yield strength criteria, design factor, and longitudinal joint factor. Requirements in this subpart address several specific threats including third party damage, previously damaged pipe, heavy rain/floods, and defective pipe.

Subpart D - Design of Pipeline Components

Subpart D contains a wide range of requirements for pipeline components including valves/fittings/flanges, other manufactured components, extruded outlets, components fabricated by welding, compressor stations and equipment, pressure relief devices, and vaults. It also covers passage of ILI tools in new lines or segments. Due to the wide scope of Subpart D, it directly or indirectly addresses 10 of the 22 threats listed in the matrix. A specific threat includes protection from vandalism that is implied in 192.163 (Compressor Station Design) and 192.179 (Valve Protection). Another example is defective fabrication welds that are addressed in sections 143, 151, 153, and 155.

Subpart E - Welding of Steel in Pipelines

Welding requirements, welder qualification, restrictions on miter joints, weld testing and inspection, repair, and nondestructive testing are covered in Subpart E. Proper attention to all of these criteria is required to produce acceptable quality field and fabrication welds. As such, many of the requirements directly address two threats including defective pipe girth weld and defective fabrication. It also addresses the threat resulting from cold weather since a properly completed and inspected weldment is essential to meet the more demanding service conditions created by low ambient temperatures.

Subpart F - Joining of Materials Other Than by Welding

This subpart contains joining requirements and limitations for steel and other materials. A major part applies to plastic pipe joining including procedure and personnel qualifications. With respect to pipeline threats, these criteria pertain to gasket/O-Ring failure, Stripped threads, and Seal/pump packing failure according to the provisions in section 273 requiring consideration of longitudinal forces and joint expansion/contraction.

Subpart G - General Construction Requirements for Transmission Lines …

Construction requirements contained in this subpart include standard and specification compliance, construction and materials inspection, steel pipe repair, bends/elbows, hazard protection, pipe installation, casing, and cover.

This subpart directly addresses the three threats in the Third Party Damage Category (third party inflicted. previously damaged pipe, vandalism) that account for a significant fraction of pipeline incidents. In particular, sections 305, 307, 309, 317, and 327 cover several requirements to prevent previously damaged pipe remaining after construction completion. The threat created by heavy rains or floods is also reduced by 317 and 327 by requiring hazard protection and sufficient depth. Another threat, defective pipe seam, is indirectly addressed by 313 which addresses the serviceability of pipe used for bends.

Subpart H - Customer Meters, Service Regulators, and Service Lines

With respect to threat mitigation on transmission pipelines, this subpart is not applicable.

Subpart I - Requirements for Corrosion Control

This scope of this subpart is focused on internal, external, and atmospheric corrosion control as applied to metallic materials. More specifically, it covers cathodic protection systems, coatings, corrosion monitoring, electrical isolation, remedial measures, and records. Three of the 22 incident causes including external corrosion, internal corrosion, and stress corrosion cracking (SCC) are addressed with emphasis on external corrosion. Application to SCC is not direct but 459 covering external examination of an exposed pipeline and 461(Coating) can apply. Coating quality is an important factor in SCC mitigation.

Subpart J - Test Requirements

Subpart J applies to strength verification and leak testing requirements of new, relocated, or replaced pipeline segments. It is aimed at detection of defects that may remain after construction is completed. Five of the 22 incident causes are affected including previously damaged pipe, defective pipe seam, defective pipe, defective girth weld and defective fabrication weld. All of these causes pertain to critical defects most likely present prior to service and can be detected by a pressure test.

Subpart K - Uprating

This subpart describes what must be done to uprate piping, frequently a concomitant action required by class location changes.

No failure criteria included in the matrix pertain to this subpart.

Subpart L - Operations

Provisions of this subpart apply either directly or indirectly to all 22 incident causes. Specific requirements include operation/maintenance and emergency response procedural manuals, class location change requirements, damage prevention program, emergency plans, public education etc. Another section (617) addresses failure investigation and analysis, which was also considered to be directly applicable to all 22 incident causes and not shown in the matrix. Root cause analysis was also considered to be a common element not specifically stated in this subpart but implied in 617.

Subpart M - Maintenance

Maintenance requirements in this subpart apply directly or indirectly to all of the incident causes except cold weather. As such, these requirements impact the most significant incident causes and the leading maintenance mitigation practices. This subpart contains a wide range of maintenance requirements including leakage surveys, line markers, repair procedures, patrolling, facility abandonment, relief device inspection and testing, valve maintenance, and accidental ignition prevention.

Section 6 - Industry Prevention and Detection Practices

The "Leading Industry Practices" column at the center of the matrix contains a group of practices that can be considered as activities pertaining to incident prevention through early detection and maintenance action to correct what may be considered as incident precursors. The second basic type of practice is included in a maintenance/repair group. In some cases, depending on the specific circumstances and application, the distinction between these two groups of practices is not clear-cut. This Chapter will focus on prevention/ detection practices and Chapter 7 will discuss the maintenance/repair practices included in the matrix.

A total of 38 leading practices included in the prevention and detection group that are being used by pipeline operators are provided in Table 6-1 below. A brief description of some practices has been provided for clarity.

Table 6-1

Prevention/Detection Practice	Description
Visual Examination	Includes all visual determinations and measurements of pipe and components.
Surface Nondestructive Testing	Includes techniques such as magnetic particle and shear wave ultrasonic testing to assess external anomalies
Surveillance/Patrol	Aerial or foot patrol of ROW, detailed visual inspection
Coating Condition Evaluation	All inspections associated with field coating evaluation of exposed buried or above ground pipe sections.
Close Interval Survey (CIS)	Aboveground potential measurement at close intervals.
Direct Current Voltage Gradient (DCVG)	Aboveground coating integrity assessment.
Bellhop Inspection	Exposure of a pipe section for examination. Usually includes visual and other NDE methods
Compliance Audit	Audit conducted by operator personnel to assure compliance with regulatory and Company procedures
CP Test Points	Required measurement of CP current at fixed test points.
Leak Survey	Required evaluation for pipeline leaks.
Geometry Tool Inspection	Inline inspection of pipe to detect obstructions, dents, pipe ovality, evaluation of clearances for inline inspection, etc.
Inline Inspection Tool (Baseline)	Inline inspection tool run in newly constructed pipe to establish initial pipe condition and detect construction damage.
Inline Inspection Tool (In-service)	Periodic inline inspection tool runs for pipeline integrity assessment.
Preservice Hydrotest	Initial hydrostatic test to validate initial integrity and detect construction and defective materials

Prevention/Detection Practice	Description
Construction Inspection	Inspection effort during pipeline construction to assure regulatory and specification compliance.
Manufacturer Inspection	Active QA/QC during pipe and component manufacture to assure initial product quality.
Transportation Inspection	Inspection during pipe/component loading to assure proper methods that minimize transportation related damage.
Hydrostatic Retest	Periodic retesting to assure continued integrity or for uprating purposes
Strain Monitoring	Installation and monitoring of the deformation extent of pipe or components as a method to assure integrity.
Ground Displacement Survey	Use of survey methods to detect and monitor the extent of pipe deformation due to unstable soil or subsidence.
Soil Corrosivity Evaluation	Laboratory evaluation of soil samples removed from a bellhole to evaluate potential corrosivity.
Resistivity Survey	Over-the-line determination of soil resistivity to estimate corrosive potential.
Rate Predictive Methods	Use of corrosion rate data to predict the time required for excessive metal loss and maintenance interval estimates.
External Coupon Monitoring	Installation and monitoring of buried coupons adjacent to pipe for corrosion monitoring and IR drop estimates.
Internal Coupon Monitoring	Installation and monitoring of coupons inside a pipeline to detect and monitor internal corrosive conditions.
Gas Analysis	Analytic determination of natural gas composition and potentially corrosive components.
Microbiological Corrosion Monitoring	Process of determining the contribution of microbiological organisms to either external or internal corrosion.
Surface Ultrasonic Inspection (B-scan)	Inspection to determine the extent and severity of internal corrosion from the outside pipe surface.
Iron Analysis	Determination of iron quantities in the gas stream as indicator of internal corrosion at upstream location(s).
Surface Radiography	Radiography to determine the presence of internal corrosion pitting damage (also pipe construction NDE).
Proper Materials Specifications	Specifications establishing required pipe/material quality for the facility design conditions.
Proper Design Specifications	Pipeline and facility design specifications that are suitable for the intended purpose.
Effective Public Education	A primary tool for third party damage prevention.
Effective Operator Personnel Training	Formal and on-the-job training processes that produce well qualified operations/ maintenance personnel.

Prevention/Detection Practice	Description
Comprehensive Construction Procedures	Complete written methods and procedures to assure high quality pipeline construction.
Comprehensive Emergency Procedures	Complete written procedures covering pipeline and facility emergency measures.
Comprehensive Operations and Maintenance Procedures	Complete documented procedures for all pipeline operations and remediation.
One Call System	Centralized state operated locations for construction activity notification and erosion and washout monitoring.

The practices described in Table 6-1 above have been extracted from the summary matrix presented in Section 4. It can be seen that a wide range of prevention and detection methods have been included. Some have a very specific scope of application while others can be used for several purposes. Also, in some cases, a specific practice may be used alone but more frequently these practices are used jointly with others to maximize their effect or improve the quality of information gained. Some of these practices are required by the regulations in 49 CFR 192 while others represent activities that are over and above regulatory requirements

With respect to prevention related activities that should occur prior to facility operation, good practice starts with comprehensive design and materials specifications that provide assurance that the pipeline and facilities will be suitable for the intended service conditions and life. Still other practices are used including manufacturer and transportation inspection to assure that correctly produced and properly coated pipe and materials reach the construction site without damage.

During the construction process, preventive measures include visual and NDE inspections and pre-service hydrostatic testing that are required by the regulations. Such hydrostatic testing is intended to eliminate critical material or construction defects that may escape detection during the construction process. Often, these actions are supplemented by optional pre-service (baseline) ILI or geometry tool runs to further verify initial pipeline integrity.

Throughout the operational life of a pipeline, a number of preventive measures are employed. They include actions required by the regulations including one call systems, written operation and emergency procedures, patrolling, corrosion monitoring, leakage surveys, and effective personnel training processes. Other additional preventive measures are also commonly used. For instance, close interval surveys (CIS), coating condition surveys using DCVG are both non-intrusive methods may both be used to provide additional data beyond that obtained by the required CP test point monitoring. Suites of test methods such as this form the basis of the Direct Assessment process that is the subject of a parallel industry effort. Additional details concerning CIS and DCVG methods are contained in (Ref. 7 - DA Report).

Third Party Damage clearly has been identified as the leading cause of gas pipeline incidents for some time. DOT and the Industry embarked on a significant program to reduce Third Party Damage. The result was the Common Ground Report (Ref. 4) and the Dig Safely Program.

The Common Ground Report (Ref. 4) identified eight significant activities in underground systems and in each of those, identified the best practices that will reduce or eliminate third party incursions.

The areas and the number of best practices are:

Design and Planning – 11
One Call Centers – 23
Locating and Marking – 17
Excavation – 28
Mapping – 18
Compliance – 5
Public Education and Awareness – 9
Reporting and Evaluations – 21

The Common Ground effort therefore identified 132 best or leading practices. Industry is continuing its efforts to implement those best practices not yet in service.

Another methodology that can be considered predictive, as well as a maintenance tool, is integrity assessment using engineering critical assessment (ECA) methods such as RSTRENG (Ref. B31G) for corroded pipe analysis. Although such methods are not always considered to be predictive tools, they can be depending on the type of application.

Similarly, a number of detection measures shown in Table 6-1 (Ref. 8) can also be used independently but are often used together. One frequent example of a multiple inspection effort occurs when bellhole excavations are used to permit visual inspection of buried pipelines, or when pipeline segments are exposed for some type of maintenance. Although records of stipulated pipeline condition assessments are required by the regulations, bellhole inspections are usually more extensive depending on perceived or known threats to that segment of pipeline. Bellhole inspections can include several of the items listed in Table 6-1 including visual inspection, surface NDT, soil corrosivity evaluation, and application of corrosion rate predictive methods. Where internal corrosion may be a threat, application of surface UT methods capable of scanning and evaluating limited areas (B-Scan) and radiography may provide an indication of internal conditions. Other methods including iron analyses, MIC analysis, gas analyses, and internal corrosion coupon monitoring are also useful in verifying the existence of an internal corrosion threat.

Hydrostatic testing is frequently employed to detect corrosion and other types of anomalies over longer pipeline lengths. ILI is effective for detecting corrosion at an earlier stage, permitting mitigation activities. ILI technology is under commercial development to detect additional anomalies such as dents, cracks, SCC. Several types of ILI tools are currently available including MFL (Magnetic Flux Leakage), TFI (Transverse Flux), UT (Ultrasonic Testing), and others. MFL tools are commercially available in low and high-resolution versions (see Ref. 9). Each type of ILI tool has an optimum application area and, therefore, must be selected carefully based on the anticipated pipeline conditions. For instance, conventional MFL tools would not be a good selection in pipelines suspected to contain selective corrosion of ERW (Electric Resistance Welded) seams but would be applicable to corroded pipelines. Additional details concerning the techniques discussed above are contained in Reference 8 (Ref GRI-91/0366)*. The following Table 6-2 excerpted from this reference illustrates a simple way of describing the applications of some of the preventive practices discussed in this Chapter.

Although the matrix shows risk assessment results as useful for establishing inspection and maintenance frequencies, such models and processes could also be considered as predictive tools. A properly designed and implemented risk assessment process is capable of predicting the location of potential trouble spots that can be evaluated prior to the occurrence of an incident.

*Table 6-3 describes in-line inspection tool applicability for the various types of anomalies found in gas pipelines.

Table 6-2. Assuring Integrity of Natural Gas Transmission Lines [1]

	R-O-W Patrol		Corrosion Control			In-Line Inspection				Bellholes		Tests
Practices / **Conditions**	Aerial Patrols	Ground Surveys	CP Measurements	Close Interval Survey	Coupons/Monitors	MFL Pigs	Geometry Pigs	Mapping Pigs	Cameras	Visual Inspection	NDE Examinations (d)	Hydrostatic Retesting*
Outside Forces												
3rd party damage	X	X					Xa		Xc	X		
Earth movements	Xb	Xb					X	X				
Metal Loss												
External Corrosion			X	Xf		X				Xd	X	X
Internal corrosion					X	X	X					X
Gouges						X				Xd	X	X
Gas Leakage	X	X								X		
Coatings			X	X						X		
Cracks												
Seam weld										Xe	X	X
Girth weld										Xe	X	X
Stress corrosion											X	X
Fatigue										Xe		
Selective corrosion										Xe	X	X
Geometry												
Ovality, buckles							X		X	X		
Obstructions, dents							X		X	X		
Ovality, wrinkles							X		X	X		
Bend radius							X	X				
Pipeline movement								X				
Metallurgical												
Inclusions						X					X	X
Hard spots						X					X	X
Laminations											X	

* Effective for Critical Defects Only

(a) Geometry Pigs are designed to detect dents and ovality
(b) Effective for landslides but not for differential settlement
(c) Designed to detect dents and wall protrusions
(d) Assumes coating has been removed
(e) Generally cannot detect without using NDT methods
(f) Locates possible corrosion resulting from inadequate CP

[1]From: GRI-91/0366

Table 6-3 - Anomaly Types and In-Line Inspection Tools to Detect Them in Natural Gas Pipelines *

ANOMALY TYPES	METAL LOSS TOOLS			CRACK DETECTION TOOLS			GEOMETRY TOOLS (CALIPER TOOLS)	GEOGRAPHY TOOLS (inertial navig. tools)
	MFL		Ultrasonic (normal beam - compression wave)	Ultrasonic (angle beam - liquid coupled)	Ultrasonic (angle beam - wheel coupled)	Circumferential MFL[14]		
	Standard Resolution	High Resolution						
METAL LOSS (CORROSION) External and Internal Corrosion	detection[1], approximate sizing[3]	detection[2], sizing[3]	detection[2], sizing[3]	detection[2],	detection[2],	detection[2], sizing[3]	not applicable	not applicable
Narrow Axial Corrosion	no detection	no detection[4]	no detection[4]	detection[2], sizing[3]	detection[2], sizing[3]	detection[2], sizing[3]	not applicable	not applicable
CRACKS AND CRACK-LIKE DEFECTS (axial) Stress Corrosion Cracking Fatigue Cracks Longitudinal Seam Weld Imperfections Incomplete Fusion (lack of fusion) Toe-Cracks	no detection	no detection	no detection	detection[2], sizing[3]	detection[2,11], poor sizing[3] sizing accuracy less than liquid coupled	detection[2,5] poor sizing[3]	not applicable	not applicable
Circumferential Cracking	no detection	limited detection and sizing	no detection	no detection[2]	no detection[2]	no detection	not applicable	not applicable
DENTS Plain Dents Wrinkle Bends/Buckles	detection[7]	improved detection[7,10]	detection[7,10] no sizing	limited detection[7,10] no sizing	limited detection[7,10] no sizing	detection[7,10] sizing not reliable	detection[8] sizing	detection, sizing not reliable
DENTS WITH GOUGES	not reliable detection	not reliable detection	detection[7] sizing not reliable	detection[7] sizing not reliable	detection[7] sizing not reliable	detection[7] sizing not reliable	dent detection[8] no sizing	dent detection, sizing not reliable
LAMINATIONS	no detection	no detection	detection	detection	detection	no detection	not applicable	not applicable
INCLUSIONS	no detection	no detection	limited detection	Detection and Possible sizing	Detection and Possible sizing	Possible detection	not applicable	not applicable
PREVIOUS REPAIRS	detection only of steel sleeves, patches and marked ClockSpring™		detection only of steel sleeves and patches welded to pipe	detection only of steel sleeves and patches welded to pipe	detection only of steel sleeves and patches welded to pipe	detection only of steel sleeves and patches	not applicable	not applicable
MILL-RELATED ANOMALIES	detection[12]	detection[12]	detection[13]	detection[13]	detection[13]	detection[12]	not applicable	not applicable
OVALITIES	no detection	no detection	no detection	no detection	no detection	no detection	detection and sizing[3]	detection sizing[3,9]

See Footnotes on next page

1. Limited by the minimum detectable metal loss
2. Limited by the minimum detectable depth, length and width of the defects
3. Defined by the specified sizing accuracy of the tool
4. If the width is smaller than the minimum detectable defect width for the tool
5. Reduced POD for tight cracks
6. Transducers to be rotated by 90°
7. Reduced reliability depending on the size and shape of the dent
8. Depending on the configuration of the tool, also circumferential position
9. If the tool is equipped for ovality measurement
10. In case of detection, circumferential position is given as well
11. Poor discrimination between inclusions and cracks with wheel coupled
12. Identifies volumetric or metal loss
13. Identifies volumetric, metal loss and planar
14. Emerging technology

*For similar information on hydrostatic testing and Direct Assessment, we refer you to the following reports:

GRI-00-0230 Determining Periodic Integrity Inspection Intervals for High Consequence Areas (Ref. 16)

GRI-00-0231 Direct Assessment and Validation (Ref. 7)

Section 7 - Industry Mitigation and Repair Practices

A second type of activities included in the "Leading Industry Practices" column at the center of the matrix (Table 4-1) are the mitigation practices that result from the detection measures discussed in the previous chapter. One of the maintenance/repair practices discussed herein is Engineering Critical Assessment (ECA), which can also be considered as a predictive method.

Table 7-1 contains a total of 31 leading maintenance and repair practices utilized by pipeline operators. A brief description of most of them has been provided for clarity.

Table 7-1

Mitigation/Repair Practice	Description
Apply external insulation	For protection from low temperature environments and frost heaves
Install heat tracing	For maintaining a minimum allowable pipe wall temperature. – Electrically heated wire on pipe.
Conduct ECA - Run as is	Conduct ECA and continue operation without additional action.
Install rectifier protection systems	Surge and lightning protection
Install pipeline insulating joints	Electrical isolation; CP system isolation; stray current control
Install shunts to ground	Electrical surge protection
Increase burial depth	Lower pipe in ditch such as a result of subsidence related soil deformation (lowering in service)
Apply weight coating/ add swamp weights	Added protective barrier; correct for flotation in wetlands
Increased wall thickness	Usually be replacing pipe and lowering risk
Rehabilitation (Inspect/Re-coat)	Remove from ditch, remove coating, inspect, replace as needed, re-coat, re-install
Repair pipeline coating	Repair defective coating of exposed pipe segments
Grind repair and ECA	Remove defect by grinding and ECA of repair area.
Adjust rectifier output	Correct CP level deficiency
Decrease operational stress	Reduce operational pressure
Pipe replacement	
Reduce operating temperature	Install cooling equipment typically at compressor discharge
Provide external protection	Add external barriers for improved TPD protection.
Increase depth of cover	Addition of backfill over pipeline
Increased line marker frequency	Increased marker frequency over and above regulations
Relocation	Re-route of pipeline around problem area
Install steel repair sleeve	Reinforce corroded or damaged pipe

Mitigation/Repair Practice	Description
Remove backfill	Relieve strain due to subsidence; slope instability.
Isolate pipeline segment	Isolate under pressure
Direct deposit weld repair	In-service weld repair of corroded pipe areas
Install composite sleeve repair	Install ClockSpring™ to reinforce corroded area
Improved CP coverage	Modify CP system to correct deficiencies
Apply protective coating (above ground)	Atmospheric corrosion protection
Mechanical leak clamp.	Repair of leaking defect
Install pressurized sleeve (pumpkin)	Repair of leaking defect
Reduce gas moisture content	Install driers, separators for dew point reduction
Biocide injection	For control of internal MIC
Inhibitor injection	For control of corrosive gas components (CO_2, H_2S)

Engineering Critical Assessment – ECA – is a generic term (see definition section after references)

Engineering critical assessment (ECA) has also been included here as a maintenance action in addition to applications covered in Chapter 5 since the same basic methods are used to verify pipe integrity. In some cases, the only maintenance action needed is an analysis to assess the integrity of a corroded area or other anomaly to verify the pipeline can be safely operated without additional action. In another case shown in Table 7-1, an ECA is performed after a grind repair to assure that the material removed while eliminating a defect does not create an unacceptable situation.

Composite sleeves (i.e., ClockSpring™ – Ref. 10) for reinforcement of corroded areas in pipelines is another maintenance method that is being used with increasing frequency. Considerable industry research on the installation and long term performance of these sleeves has demonstrated that they are an effective, safe repair method. Additional information on the long-term reliability of composite sleeves can be found in Ref. 10. (Long-Term Reliability of Gas Pipeline Repairs by Reinforced Composites, SwRI and Battelle)

Section 8 – Integrity Management

Integrity Management is a systematic process for continually assessing, evaluating and remediating the integrity of systems through prevention, detection and repair techniques, comprehensively evaluating and integrating all data and analyses in an iterative manner.

This section defines integrity management as a process, describes how the process works and then provides examples of the application of the process.

Figure 8-1 depicts integrity management as a process. There are five steps in the process. They are:

1. Assessment by segment (data integration)
2. Define threats
3. Select prevention practices
4. Select detection practices
5. Select mitigation practices

Viewing integrity management as a process implemented in a sequential fashion provides the greatest potential for reducing incident frequency and the potential for catastrophic events. The importance of a sequential implementation is best exemplified by examining the fundamentals of third party damage, the leading cause of reportable pipeline incidents. Third party damage is damage inflicted on the line pipe in right of way by personnel, generally with mechanically-driven excavation equipment. Experience demonstrates that in cases where third party damage has led to an incident, 88% of the cases result in immediate consequences (Ref. 15). The most effective way to reduce the likelihood and therefore the consequences of most third party damage incidents is to direct significant resources towards prevention practices. This is why the industry in cooperation with the Office of Pipeline Safety, and public interest groups committed the time and resources to develop the leading practices under the Common Ground Initiative. Simply directing resources to trying to detect third party damage, in lieu of properly applying prevention practices, is not sound business.

The first step in the process is to conduct an assessment of the system that reflects information and data on the properties of the line pipe, construction and service history, operating and work history, the surrounding environment, and the mode(s) of protection for the pipeline. The assessment also includes a review of inspection and testing conducted. This will also include a review and evaluation of all exposed pipe reports, with an emphasis on observations concerning presence or absence or corrosion, nature and extent of corrosion when present, observations about coating condition and other aspects of the line pipe integrity. This step has been referred to as “data integration”, as it entails, as the name suggests, integration, review and evaluation of a variety of data sources to develop a profile or a picture of the integrity of the line. The use of index-based risk assessment tools provides a platform for data integration. Many natural gas transmission companies use index-based tools as a part of risk management programs begun in the mid-1990s. While index-based models consider risk in a relative, not absolute sense, data on the pipeline system are compiled and stored with the model. This provides the basis upon which to conduct the types of analyses that constitute this assessment function. One way to view this step is to view it as a risk-based assessment of the condition of the system, based on available data. Index-based models also provide a means to integrate expert judgment with available data.

One question that often arises is how does one decide how to segment a system. In our experience, the basis for segmentation should consider the resolution of the data being used and what size of a segment provides a meaningful basis to consider in assessing condition; e.g. - do the data on the condition of the system reflect one foot intervals or one mile intervals? Do the data represent discrete measurements along the system or are they continuous? The outcome of this assessment is to create a uniform system-wide understanding of the physical condition of the system. It is not to identify the segments that pose the greatest risk. Defining the segments that warrant additional work or pose the greatest risk can only be done when factoring in the nature of the threats to the pipeline. Jumping too quickly to identifying segments that appear to be the greatest risk can lead to ineffective use or allocation of resources, and actually divert resources away from more significant risks.

The second step is definition of the threats to the segment under consideration. This step is important because it ensures that subsequent efforts will be directed at actual threats reflecting the condition of the line. Subsequent efforts are the steps that follow, prevention, detection and mitigation. For example, it would be imprudent to apply a detection tool, such as magnetic flux leakage (MFL), to a line where there were concerns about the coating quality without first establishing that corrosion was in fact a threat to the segment under consideration. While it might seem plausible to assume this, the cathodic protection on the system may have been more than adequate alone to protect the metal integrity, and the nature of the surrounding soils may not be conducive to corrosion. In fact, the best means of managing integrity might be to conduct an above ground coating quality assessment using Direct Assessment methods such as direct current voltage gradient (DCVG) technology, and then dig and repair the coating in those areas of concern. If on the other hand, records on the adequacy of the cathodic protection are not complete, the soil conditions are conducive to a corrosive environment and therefore there is reason to be concerned about external corrosion, the operator may choose to select pigging using Table 6-3. The operator may find it prudent to first apply one of the Direct Assessment methods such as DCVG to target areas of potential concern. The DCVG will identify areas where the coating is disbonded which are an indication of the potential for formation of corrosion sites. Then depending on the prevalence and extent of the anomolies identified with DCVG, the operator can develop a plan to make digs and repair/replace/monitor, or run a pig.

Defining threats takes into account data and information gathered in the previous step. One evaluates the land use, with particular emphasis on soil characteristics and construction activities, the chemistry of surrounding soils, the potential for land movement and heavy rainfall, and the history of the line pipe itself, including how it was manufactured. The twenty-two causes defined in Section 3 can be used as the basis for initiating the analyses. Causes or threats can be systematically selected or rejected for further consideration based on the evaluation of the historical data and information.

Having identified the threats to integrity, one can review the myriad of prevention practices outlined in Section 6. Again, the importance of prevention cannot be overstated. Prevention is the first course of action to take in reducing or eliminating a threat. Then having defined applicable prevention practices, gaps identified in managing these threats are addressed by selecting detection practices. The purpose of detection practices is to identify the presence or absence of the threat along the segment being addressed, and where present the extent to which the threat exists. For example, if external corrosion is a threat then one might select pigging to identify the presence or absence, and the extent of corrosion. As shown in Table 6-3, metal loss tools such as a magnetic flux leakage pig might be selected for testing. But as shown in the example below, direct assessment may be an appropriate means of detecting the external corrosion.

The last step in the process entails selecting practices to either repair or replace the line pipe based on the nature and extent of the problem identified through employing the detection practices. Section 7 provides a variety of practices and a brief description of each. A final important aspect of this last step is that work done on the line pipe and other information relating to the condition are gathered and made available to update the database. In this manner, this process is continuous in that evaluation of new data and information may cause one to consider additional threats or select additional prevention, detection and repair or replacement practices. Likewise, the new data may warrant that a threat no longer be considered significant for a segment or series of segments.

Figure 8-2 schematically shows how the gas transmission pipeline industry is performing the process now for two threats/causes of pipeline failures, Third Party Damage and External Corrosion. In the example, prevention practices embodied within the current regulations are listed with their respective subsection within 49 CFR 192 (e.g.- subsection 103 for General Design). Prevention practices in use that exceed the current regulatory requirements are listed as well; examples include one call and increased patrols for third party damage and a close interval survey for external corrosion. Figure 8-2 also depicts detection practices used to manage integrity. Selection of the applicable and ultimately most appropriate detection practice will depend on the evaluation of historical data and information and the effectiveness of prevention practices.

For example, a review of exposed pipe reports and field notes from a line pipe replacement project a year ago indicated the presence of general corrosion of the surface of selected locations adjacent to where the work was done. Additional pipe was exposed to ensure that the full extent of corrosion was identified. The corrosion did not warrant action at that point. However, there was concern about the corrosion rate so coupons were placed along the line prior to replacing the cover. A leak survey was conducted as required by the regulations. Soil corrosivity measurements were made and then checked periodically. In addition, the cathodic protection on the segment was upgraded. An engineering critical analysis based on pipeline inspection reports was conducted annually to ensure that the pipe could be operated safely. In line inspection would be considered once the data demonstrated that the corrosion could have progressed to an extent to cause the line pressure to be derated. From the knowledge gained from these evaluations, repairs may be required and grinding, sleeves, or pipe section replacement are all viable repair techniques.

Current DOT regulations have provisions for mitigating the twenty-two threats, from the initial design of a pipeline system, through its daily operation. These are detailed in Appendix A. In addition, One Call Systems implementation increased patrols above and beyond 192 requirements, and such innovative approaches as a repeat offender database, all help to reduce Third Party Damage. In addition, the Gas Pipeline Industry has fully participated in the Common Ground Initiative. Through this process, 132 separate best practices have been enumerated for significantly reducing Third Party Damage to buried systems (Section 7).

Taken in a broader context, pipeline companies using leading practices, perform system-wide integrity management by:

1. Assessing each segment – its history, service and environment.
2. Assessing the risks in each segment – defining potential threats.
3. Developing and implementing an integrity plan based on the assessed risks – selecting prevention practices selecting detection practices.
4. Performing post inspection mitigation and analyses-repairs and determining revised inspection intervals

A brief discussion of how industry interprets and implements paragraph 49 CFR 192.613 is given at the end of Appendix A. This interpretation and implementation have provided a foundation to build on for managing pipeline integrity.

The Process of Managing Integrity

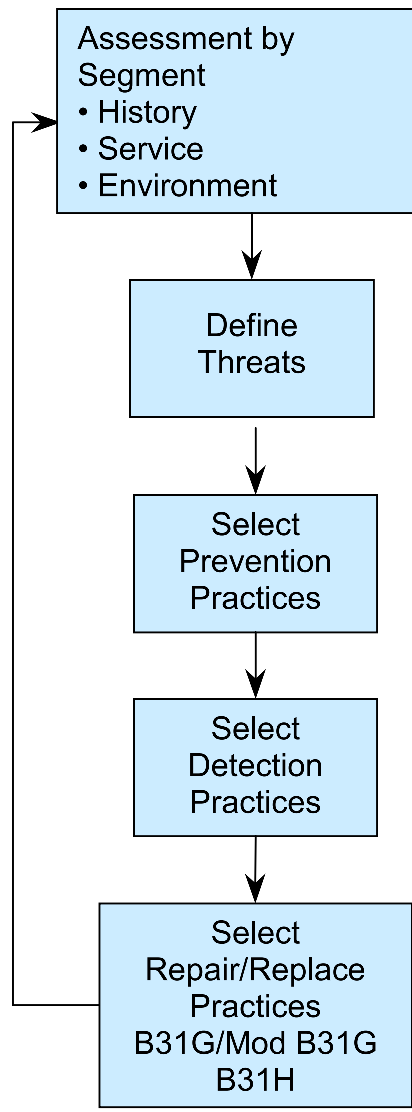
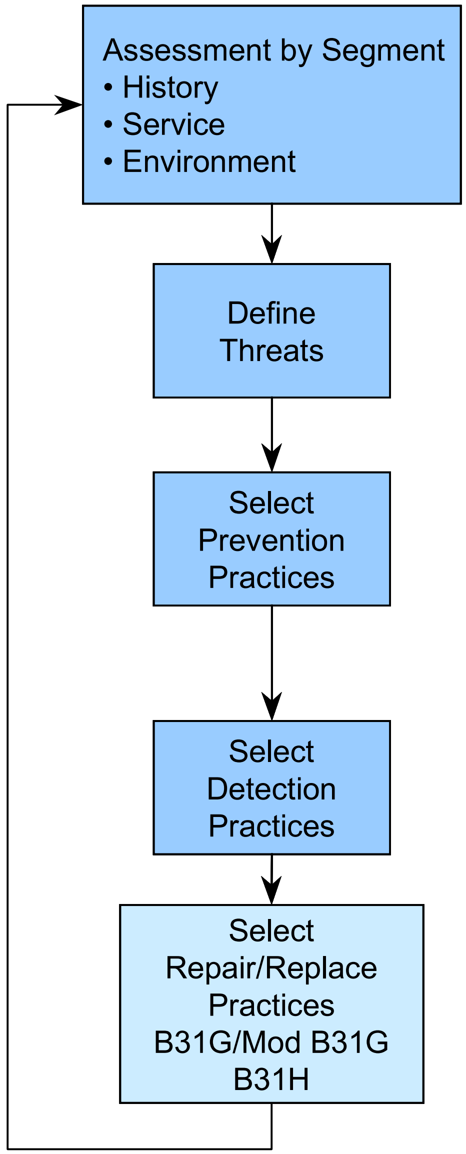


Figure 8-1

The Process of Managing Integrity



Third Party	***External Corrosion***
103 - General Design 111 - Design Factor 317 - Hazard Protection 327 - Cover 613 - Surveillance 614 - Damage Prevention 616 - Public Education 705 - Patrol 707 - Line Markers	455 - General Post 1971 457 - General Pre 1971 459 - Examination 461 - External Coating 463 - Cathodic Protection 465 - Monitoring 467 - Electrical Isolation 469 - Test Stations 471 - Test Leads 473 - Interference
One call Increased patrols Repeat offender database	Close interval survey Direct current voltage gradient
Hydrotest ILI (Geometry, Low Res) Coating Condition Eval	705 - Leak Survey Buried coupons Soil corrosivity Upgrade CP
	Pressure Testing Inline Inspection
Grind repair Composite sleeve Direct weld deposition Pipe replacement	Recoat Mechanical clamp Pressurized sleeve Composite sleeve Direct weld deposition Pipe replacement

Figure 8-2

Section 9 - Integrity Management Programs for HCAs

While the gas pipeline industry has been managing its systems' integrity, the proposed Integrity Management Programs described in this section are more comprehensive, systematic and integrated. Data integration and iteration and comprehensive industry standards for these programs are significant additions to managing integrity.

The following provides an outline of what a Gas Transmission Pipeline Industry Standard for Integrity Management in High Consequence Areas should include.

It is developed with the definition in section 8 in mind: - Integrity Management is a systematic process for continually assessing, evaluating and remediating the integrity of systems through prevention, detection and mitigation techniques, comprehensively evaluating and integrating all data and analyses iteratively.

Fig. 9-1 schematically shows the framework for such a standard that includes all of these elements.

In addition to the Integrity Management Standard, the Gas Transmission Pipeline Industry is in the process of developing a number of supporting standards. Adding these to the existing regulations and B31.8, will provide a complete set of Codes and Standards for developing and implementing integrity management programs that can meet the proposed Integrity Management Rule.

The following are the standards that are in various stages of development that will supplement the Integrity Management Standard:

Corrosion Assessment - This is an update and perhaps a re-write of the ASME B31 G standard to bring it more in line with current research and practices using updated RSTRENG for more accurate analyses. This should continue to be an ASME document but not necessarily under the B31 committee.

Dent and Gouge Assessment - This will be a new standard under ASME similar to the one for corrosion assessment in form and format. This would be based on research and current industry practices. This may or may not be under the B31 committee.

Hydrostatic (Pressure or Strength) Testing - This will be a new standard under ASME that would address testing for new pipelines as well as testing for in-service pipelines for the purpose of periodically proving integrity, utilizing the most current research and industry practices. This may or may not be under the B31 committee.

Smart Pigging - This will be a NACE standard that addresses tool selection, tool capabilities, etc. The current designation is T10E6.

Direct Assessment - This will be a NACE standard that addresses the direct assessment methodology including use of various tools to determine pipeline integrity. The current designation is T-10B8.

Stress Corrosion Cracking Assessment - This will be a NACE standard that addresses how to predict and sample for the occurrence of SCC and recommendations for managing SCC if it is found. It will be based on current industry practices and research. The current designation is T-10E7

Internal Corrosion Control - This will be a NACE standard that addresses how to predict and sample for the occurrence of internal corrosion on pipelines and recommendations for managing it if it is found. There is no current standard; however, one did exist previously.

External Microbiologically Induced Corrosion (MIC) - This will be a NACE standard that addresses how to predict and sample for MIC and recommendations for managing MIC if it is found.

Corrosion Control Monitoring Techniques - This will be a NACE standard that addresses the current industry practices and recent research in the area of monitoring for external corrosion on pipelines.

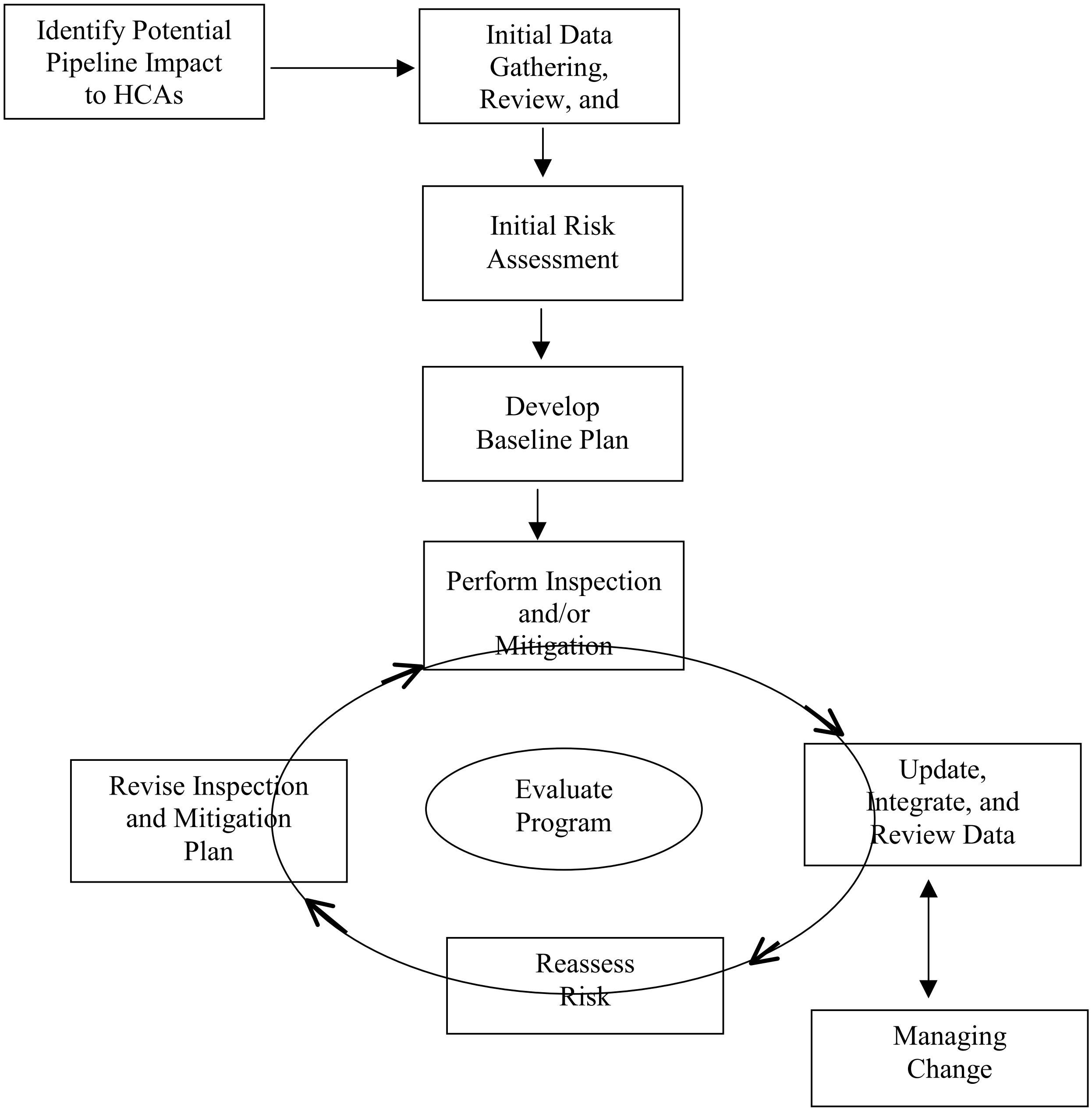
High Consequence Affected Area Determination - This will be a recommended practice or guide on how to determine whether or not a pipeline falls under the integrity management regulations for HCA's. The ultimate location of this document is not determined but may best fit within the GPTC organization and charter as it is a refinement/interpretation of a regulation.

Integrity Management Development Guide - This will be a recommended practice or guide on how to comply with the prescriptive portions of the Integrity Management Rule. The ultimate location of this document has not been determined but may best fit within the GPTC organization and charter as it is a refinement/interpretation of a regulation,

Risk Based Integrity Management - This will be a standard or recommended practice on how to develop an integrity management program as an alternative to the prescriptive regulation. The ultimate location of this document is not determined but may fit well within the ASME realm provided that ASME begins development of Operation and Maintenance standards that compliment their Design and Construction Standards.

Integrity Management programs will be developed and implemented based upon the Integrity Management Rule, the Integrity Management Standard and all the supporting standards listed above. This will provide a structured framework for the entire industry to follow, ensuring a level of compliance commensurate with the intent of the rule, but allowing companies to integrate this initiative with the many other integrity efforts they presently perform.

Figure 9-1
Integrity Management Program Outline



-

INTEGRITY MANAGEMENT FOR HCA'S –
DRAFT STANDARD OUTLINE

The Standard for Integrity Management in High Consequence Areas should include the following elements:

1. INTRODUCTION
   What is I/M, Define HCA's
   Purpose & Objectives
   Guiding Principles

2. SCOPE
   Includes pipelines & ROW facilities within defined HCAs
   Baseline testing and subsequent testing that include: hydros, ILI, D.A. & other appropriate methods.
   All data & information to be integrated and analyzed to determine integrity. Further testing required until integrity is assured.
   System integrity to be considered during design & construction phases as well.
   While specific to HCA's, standard can be applied to any and all pipeline facilities.

3. REFERENCES & STANDARDS
   Include 9 standards being prepared + B31.8 etc. and 192, GPTC

4. TERMS, DEFINITIONS & ACRONYMS
   Take material from NPRM, HCA, Risk Mgmt., Integrity Mgmt.

5. INTEGRITY MANAGEMENT PROGRAM OVERVIEW
   A. Prescriptive Program
      1. Identify pipelines within HCAs.
      2. Gather all historical data on pipelines within HCA, including: pipe age, pipe material, construction, previous testing, dates, results, methods etc.
      3. Integrate data to determine pipe integrity, rate of possible deterioration etc.
      4. Based on OPS rules, is last integrity test an adequate baseline, if so, schedule next test accordingly and choose by what method. If not, schedule for testing by appropriate method to meet OPS guidelines and timeliness requirements.
      5. Analyze results – mitigate or/and schedule for next testing interval per OPS rule.
      6. Review performance measures and update 2-5 as appropriate.

6. IDENTIFYING HCA'S ALONG YOUR ROW
   Definitions of HCAs
   How to determine pipeline potential impacts
   Mapping your pipeline in HCA's

7. GATHERING, REVIEWING, INTEGRATING DATA
   What data to gather
   Data review and analysis
   Data integration processes
   Reporting

8. DEVELOPMENT OF INITIAL BASELINE PLAN
   Determining what inspections must be performed and when
   Baseline plan development

9. INSPECTION / MITIGATION
   Inspect per plan
   Analyze data
   Mitigation activities as required from testing results
   Enter all data and information into I/M Plan

10. CONTINUING INSPECTIONS/MITIGATIONS PLAN
    Integrate results from 9.
    Following OPS Rules- set up next inspection intervals/methods

11. REPORTING & EVALUATIONS
    Reports to OPS – contents etc.
    Pipeline evaluations
    Program evaluations
    Performance measures

12. REVIEW PERFORMANCE & IMPROVE INTEGRITY MANAGEMENT PLAN
    The feedback for continuous improvement

13. COMMUNICATIONS PLANS
    Communications with regulators, employees, public, emergency organizations.

Section 10 – Industry Safety R&D Initiatives

The Gas Transmission Pipeline Industry has always spent significant sums to improve its performance, especially in the area of safety.

Three groups account for the bulk of the spending for transmission systems safety R&D:

GRI – Gas Research Institute (now GTI)
PRCI- Pipeline Research Council International
Industry – Individual Companies, INGAA Foundation etc.

For the 5-year period of 1995-1999 inclusive, GRI has spent more than $66 million on gas transmission systems safety and reliability. Areas include Inspections, Maintenance, Safety, Operations, Compressors, Measurement, Storage, Corrosion and Non Destructive Examinations. For the same 5 year period, PRCI has spent more than $9 million just on line pipe, Corrosion and Non Destructive Examinations. Combined, GRI & PRCI have spent more than $33 million in those 5 years on the subjects of, corrosion, line pipe and NDE alone.

To these sums must be added two unmeasured but significant sums of money:

1. Company in-house research and development programs
2. Industry management and support of R&D programs, codes and standards efforts, and the use of their people and facilities for field trials and commercialization.[1]

Based upon industry activity over the past 5 years, it is conservatively calculated that these expenditures are more than $5 million per year.

Therefore, for the 5 year period, the industry as a whole, has spent more than $100 million on safety and reliability research and development.

Appendix B - NATURAL GAS PIPELINE INDUSTRY RESEARCH & DEVELOPMENT – PIPELINE INTEGRITY & SAFETY, provides an overview of the areas of concentration and results achieved to date.

Appendix C - RELEVANT R&D lists by the 22 causes and several other categories, applicable R&D that has been performed in approximately the past 10 years. This is a condensation of what is called the GRI "Yellow Pages", a full compendium of all R&D performed for transmission systems with brief explanations of each work and its results. This report GRI-00/0192 (Ref. 13) is available from GTI.

[1] Industry considers a technique or capability COMMERCIALIZED when they can obtain it through normal quoting processes, in a real-time framework with fully field demonstrated repeatable results.

The matrix (Table 4-1) includes an abbreviated listing of significant R&D that is relevant to each of the 22 causes. Due to space limitations, only 4 or 5 most recent and directly applicable and varied activities are listed. The 2 appendices provide much greater details.

DOT has been a limited partner in these R&D activities, especially in the NDE area. Per Reference 11,

> "Of the $10MM in OPS's research program between 1995 and 1999, approximately 75% was spent on risk assessment, mapping, and information analysis. OPS has funded research on smart pig technology, spending $2.5MM from FY1995 through 1999 to assess and verify smart pig capabilities."

One objective for developing and displaying all of this information is to permit Industry and DOT to jointly find areas that need greater exploration and hopefully obtain support and funding from DOT and Industry in these areas.

From an industry perspective, further research can be meaningfully employed to:

1. Further inspection capabilities to detect and characterize SCC.
2. Improve ROW monitoring for encroachment, line hits and damage.
3. Developing additional non-intrusive methods for coating and external pipe condition assessment.
4. Develop nondestructive evaluations of unpiggable lines

The Inspector General's report, reference 11, recommends the following relative to R&D: "Expand the focus of RSPA research and development programs to include (a) smart pigs that can detect pipe material defects, and (b) alternative pipeline inspection and monitoring technologies for pipelines that cannot accommodate smart pigs."

RSPA's position stated – "Research on Inspection Technology – FY2001 funding request for research, recognizes the need to begin development of alternative inspection and monitoring technologies."

The second objective is to provide a convenient compendium of relevant R&D to the 22 threats/causes and to show how much industry has done and where its efforts have been expended.

Lastly, it is important to note how much new technology plays a role in improving safety and it is important to frame legislation in such a way that new, beneficial technologies and methods can be utilized advantageously.

List of References

1. GAO/RCED-00-128 Pipeline Safety, May 2000

2. J. Kiefner, et al – Analysis of DOT Reportable Incidents for Gas Transmission Pipelines and Gathering Systems, RCI Contract #218-98-01, March 1999

3. Allegro Energy Group – The Safety Performance of Natural Gas Transmission and Gathering Systems, GRI-00/0077, March 2000

4. Common Ground Report (DOT Website – www.dot.gov)

5. GRI Report Nos. 95/0228.1, 2, 3 and 4 – Risk Management

6. GRI-98/0367

7. GRI-00-0231 - Direct Assessment and Validation

8. Posakony et al – Assessing the Integrity of Natural Gas Transmission Pipelines, GRI-91/0366

9. H. Noel Duckworth – Smart Pigs Offer More Definitive Integrity Data – Pipeline and Gas Industry, June 2000

10. D. R. Stephens – Summary of Validation of ClockSpring™ for Permanent Repair of Pipeline Corrosion Defects, GRI-98/0227

11. DOT-IG Audit Report – Pipeline Safety Program Report No. RT-2000-069, March 13, 2000

12. ASME B31G

13. GRI-00/0192 – Compendium of Gas Pipeline Industry Research

14. ASME/CRTD – Vol. 43 – History of Line Pipe Manufacturing in North America

15. GRI-99/0050 – Effectiveness of Various Means of preventing Pipeline Failures From Mechanical Damage

16. GRI-00-0230 – Determining Periodic Integrity Inspection Intervals for High Consequence Areas

Definition of Terms

<u>49CFR192</u>

An abbreviation for primary regulation issued by the Research and Special Programs Administration, DOT governing minimum standards for interstate natural gas pipelines titled " Part 192- Transportation Of Natural And Other Gas By Pipeline: Minimum Federal Safety Standards. It is contained in Title 49 of the Code of Federal Regulations Subchapter D, Pipeline Safety.

<u>Class Location</u>

A requirement contained in 49 CFR 192 that define the requirements for four different class locations (1-4) based on the number and type of structures adjacent to a pipeline intended for human occupancy. Class 1 locations have the fewest structures and Class 4 locations contain multistory buildings. The extent of a class location has been defined in terms of a "class location unit" which is an area extending 660 feet on either side of a pipeline with a one-mile continuous length.

<u>Root Cause Analysis</u>

A family of processes implemented to determine the primary cause of an event. These processes all seek to examine cause-and-effect relationship through the organization and analysis of data. Such processes are often used in failure analyses.

<u>Microbiologically Induced Corrosion</u>

Corrosion or deterioration of metals resulting from the metabolic activity of microorganisms. Such corrosion may be initiated or accelerated by microbial activity.

<u>Electric Resistance Welded (ERW)</u>

One of the welding processes used for line pipe production. It involves the passage of current across an open gap, which creates the heat required to permit fusion of the abutting edges of a rolled shape. No filler metal is added.

<u>Double Submerged-Arc Welded (DSAW)</u>

The application of submerged-arc welding for line pipe production. In line pipe production, this includes one weld pass from the outside and one from the inside of the formed pipe. In this process, the welding arc is submerged in a granular flux for shielding.

High Consequence Areas

Generally an area along a pipeline with an increase in relative population density or in crossing certain waterways. In this report, class 3 and 4 locations are considered to be close approximations to an HCA. The definitive definition for gas pipeline HCAs will be issued by DOT in the forthcoming rule making.

Engineering Critical Acceptance

A generic term that implies the application of analytic methods, often based on fracture mechanics principles, to determine the acceptability of a structure for continued operation containing an anomaly. Other terms including fitness-for-purpose analysis have also been used.

RSTRENG/B31 G

Semi-empirical analytic methods used to estimate acceptability of corroded line pipe for continued service (fracture mechanics is the basic analytical tool).

A comprehensive management decision support process that is implemented as a program, integrated through defined roles and responsibilities into daily operations, maintenance, engineering, management, and regulatory decisions of the facility.

Integrity Management

Integrity Management is a systematic process for continually assessing, evaluating and remediating the integrity of systems through prevention, detection and mitigation practices, comprehensively evaluating and integrating all data and analyses, in an iterative manner.

Piggable/Non-Piggable

Terms that indicate the configuration of a pipeline or segment with respect to its ability to be inspected with an ILI tool or "smart pig." This definition has been divided into four categories. These definitions and the approximate fraction of pipeline miles in each category, based on an INGAA survey for interstate natural gas transmission pipelines, is as follows:

- Easily piggable - Launchers/Receivers available 35.4%
- Piggable without extensive work - Temporary launchers/receivers; temporarily remove valves. 19.2%
- Cannot be pigged without extensive modifications - Remove/replace bends; service suspension. 40.1%
- Cannot be pigged; wireline pig not feasible 2.9%

ROW

A strip of land over which pipelines, railroads, power lines, and other similar facilities are constructed. It secures the right to pass over property owned by others and ROW agreements only allow the right of ingress and egress. The width of the ROW is negotiated with each affected landowner.

A Useful List of Acronyms

ANSI	American National Standards Institute
API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing and Materials
CIS	Close interval survey
CRA	Corrosion resistant alloy
DCVG	Direct current voltage gradient
DOT	Department Of Transportation
DSAW	Double submerged arc welded
ECA	Engineering Critical Assessment
EPRG	European Pipeline Research Group
ERW	Electric resistance welded
GAO	Government Accounting Office
GPTC	Gas Piping Technology Committee
GTI	Gas Technology Institute (formerly GRI – Gas Research Institute)
HCA	High consequence area
ILI	In-line inspection
MAOP	Maximum Allowable Operating Pressure
MFL	Magnetic flux leakage
MIC	Microbially induced corrosion
MPI	Magnetic particle inspection

NACE	National Association of Corrosion Engineers International
NDE	Nondestructive evaluation
NFPA	National Fire Protection Association
NRC	Nuclear Regulatory Commission
OSHA	Occupational Safety and Health Administration
OPS	Office of Pipeline Safety
PRCI	Pipeline Research Council International
ROW	Right-of-way
RSPA	Research & Special Projects Administration
SCC	Stress corrosion cracking
TCF	Trillion cubic feet
TFI	Transverse flux inspection
UT	Ultrasonic testing

APPENDIX A

Gas Transmission Pipelines
Causes/Threats of Pipeline Incidents and Their Related 49 CFR 192 Requirements

<table>
<tr><th>Cause of Failures</th><th colspan="2">192 Requirements</th></tr>
<tr><th></th><th>Primary [1]</th><th>Secondary [1]</th></tr>
<tr><td>Third Party Damage</td><td></td><td></td></tr>
<tr><td>• Vandalism - V</td><td>179 - (Valve prot)
- protected from tampering and damage
317 - (Hazard prot.)
See PDP
327 - (Cover)
See HRF
613 - (Surveil)
See PDP
614 - (Damage Prevent)
See PDP
705 - (Patrol)
- should have patrol program to observe service condition
- frequency not longer than:
<table><tr><th>Class</th><th>Hwy. & RR X-ing.</th><th>All other places</th></tr><tr><td>1, 2</td><td>7½ mos.. at least twice calendar yr.</td><td>15 mos., at least once calendar yr.</td></tr><tr><td>3</td><td>4½ mos., at least 4 times each calendar yr.</td><td>7½ mos., at least twice each calendar yr.</td></tr><tr><td>4</td><td>4½ mos., at least 4 times each calendar yr.</td><td>4½ mos., at least 4 times each calendar yr.</td></tr></table>- Methods can be walking, driving, flying, or other means</td><td>615 - (Emerg plan)
- must establish written procedure to minimize hazards</td></tr>
</table>

Cause of Failures	192 Requirements	
	Primary (1)	**Secondary** (1)
Third Party Damage Continued		
• Previously damaged pipe – PDP (Delayed failure mode)	65 - (Pipe transp.) - pipe opt. greater than 20% SMYS if 70 to 1 (dia. to wall) rating or more and transp. by rail can not be used unless transp. in accordance with API RP 5L1. Pipe transp. before Nov. 12, 1970 be tested to 1.25 MAOP in class 1; 1.5 MAOP in class 2, 3, and 4 103 - (Gen. Design) - pipe must be designed with sufficient wall thickness, or withstand anticipated external pressure and load that will be imposed on pipe 111 - (Design factor) - the appropriate design factor must be used depending on where the pipe is installed, Class locations, compressor stns., road, and RR X-ing, and fabrications 305 - (Insp-Gen) - each transmission pipeline constructed must be insp. for compliance 307 - (Const insp) - pipe and other component must be visually insp. on site of installation for damage 309 (Const. repair) - each imperfection or damage that impairs the serviceability of a length of pipe must be repaired or removed 317 - (Hazard prot) - protect pipeline from washouts, floods, unstable soils, landslides, or other hazards caused by pipeline movement. Also, protect offshore pipeline from mud slides, water currents, hurricanes, ship anchors, and fishing operations. Onshore pipelines must be protected from vehicular traffic. Platform risers must be protected. 327 - (Cover) - minimum cover requirements See HRF	

Cause of Failures	192 Requirements	
	Primary (1)	**Secondary (1)**
Third Party Damage Continued		
• Previously damaged pipe – PDP (Delayed failure mode) (Continued)	503 - (Gas test reqm'ts.) - no persons may operate a new pipeline, or return to service a segment of pipeline that has been relocated, or replaced, until it has been tested to substantiate MAOP 613- (Surveil) - shall have procedures to determine and take action concerning changes in class locations, failures, leakage history, corrosion, cathodic protection and other unusual O&P conditions. Take action to recondition, or reduce MAOP in accordance with 619 (a) and (b) 614- (Dam. Prevent) - written program to prevent damage from excavation activities - participation in one call system 616- (Public educat) - establish a continuing educational program to enable customers, public, government organizations and persons engaged in excavation activities to recognize pipeline emergencies and report to operator 705- (Patrol) See V 706- (Leak survey) - leakage surveys must be conducted once a calendar year, not to exceed a 15 mo. interval - however, leakage surveys with a leak detector must be made when gas unodorized in class 3 location, at least twice a year, not exceeding a 7½ mo. interval; class 4 locations 4 times each calendar year, not exceeding a 4½ mo. interval	

Cause of Failures	192 Requirements	
	Primary (1)	**Secondary (1)**
Third Party Damage Continued		
• Previously damaged pipe – PDP (Delayed failure mode) (Continued)	707- (Line markers) - required to be placed and maintained over each transmission and main at public road x-ing and RR x-ing and where ever necessary to reduce possibility of damages or interference - marker not required offshore, or at x-ing under waterways and other bodies of water, or in Class 3 or 4 when impractical - pipeline above ground where accessible to public, markers are required - specific information is required on markers	
• Third Party inflicted damage – TP (Instantaneous/immediate fail)	103- (Gen Design) - pipe must be designed with sufficient wall thickness, or withstand anticipated external pressure and load that will be imposed on pipe 111- (Design factor) - the appropriate design factor must be used depending on where the pipe is installed, Class locations, compressor stns., road, and RR x-ing, and fabrications 317- (Hazard prot) - protect pipeline from washouts, floods, unstable soils, landslides, or other hazards caused by pipeline movement. Also, protect offshore pipeline from mud slides, water currents, hurricanes, ship anchors, and fishing operations. Onshore pipelines must be protected from vehicular traffic. Platform risers 327- (Cover) See HRF 613- (Surveil) - procedure for continuing surveillance of facilities to determine and take action for changes in O&M	

Cause of Failures	192 Requirements	
	Primary (1)	**Secondary** (1)
Third Party Damage Continued		
• Third party inflicted damage – TP (Instantaneous/ immediate fail) (continued)	614- (Damage Prevent) See PDP 616- (Public educat) - establish a continuing educational program to enable customers, public, government organizations and persons engaged in excavation activities to recognize pipeline emergencies and report to operator 705- (Patrol) (See V 707- (Line markers) - required to be placed and maintained over each transmission and main, at public road x-ing and RR x-ing and where ever necessary to reduce possibility of damages or interference - marker not required offshore, or at x-ing under waterways and other bodies of water, or in Class 3 or 4 when impractical - pipeline above ground where accessible to public markers are required - specific information is required on markers	
Corrosion Related		
• External - EC	455-(Gen. Post 1971) - must be protected from corrosion by coating and cathodic protection must be installed within 1 yr. after construction - except if an operator can demonstrate by tests, investigation, or experience a corrosive environment does not exist the above does not apply. However, if test required after 6 mo. indicate a corrosive condition does exist, cathodic protection must be applied 457- (Gen. Pre-1971) - must have cathodic protection	603- Gen Oper) (See above) 613- (Survil) - each operator shall have a procedure for continuing surveillance to determine and take action concerning changes in class location, failures, leakage history, corrosion, changes in cathodic protection requirements and unusual O&P conditions

Cause of Failures	192 Requirements	
	Primary (1)	**Secondary** (1)
Corrosion Continued		
• External – EC (Continued)	459- (Examination) - examine pipe when exposed for corrosion, if found, remedial. action required. Also, determine extent of corrosion 461- (Ext. coating) - external coating must be applied on properly prepared surface, sufficient adhesion, sufficiently ductile to resist cracking, sufficient strength to resist damage in handling and soil stress and compatible with cathodic protection - coating must have low moisture absorption and high electrical resistance - coating must be inspected just prior to lowering in pipe - coating must be protected from damages by ditch conditions or supporting blocks - coating must be protected during installation by boring, driving, or other methods 463- (CP) - cathodic protection must comply with one or more criteria in Appdx. D - If amphoteric metals are included in the system they must be isolated and cathodic protected - the entire system must be cathodically protected at a cathodic potential that meets requirements of Appdx. D for amphoteric metals - cathodic protection system must be controlled not to damage coating 465- (Monitoring) - once a yr. (not exceeding 15 mos. interval) rectifier, 6 times calendar yr (not exceeding 2½ mos. interval) - interference bond, 6 times calendar yr (not exceeding 2½ mos. intervals)	

Cause of Failures	192 Requirements	
	Primary [1]	Secondary [1]
Corrosion Related Continued		
• External – EC (Continued)	467- (Elect isolation) - must electrically isolate from other structures or interconnect cathodically protected as a unit 469- (Test stations) - must have sufficient test stations or other contact points to determine the adequacy of cathodic protection 471- (Test leads) - must be connected to pipeline to remain mechanically secure and electrically conductive - must be connected to pipeline with minimum stress concentration on the pipe - connection must be coated with insulating material compatible with coating and wire insulation 473- (Interference) - continuing program to minimize detrimental effect of strong currents - impressed current or galvanic anode system must be designed and installed to prevent adverse effects on existing adjacent underground metallic structures 479- (Atmospheric) - aboveground pipelines must be protected from corrosion. If corrosion is found remedial measures must be made if required 481- (Atmospheric) - onshore reevaluate each exposed pipeline at intervals not exceeding 3 yrs. And take remedial action if corrosion is found - offshore reevaluate each exposed pipeline at intervals of each calendar yr. not to exceed 15 mos. and take remedial action if corrosion is found 483- (Remedial-Gen) - replacement pipe must have properly prepared surface and externally coated - must be cathodically protected	

Cause of Failures	192 Requirements	
	Primary (1)	**Secondary** (1)
Corrosion Related Continued		
• External – EC (Continued)	485- (Remedial) - pipe with general corrosion must be replaced, or repaired, or pressure reduced to be commensurate with remaining wall thickness as determined by ASME/ANSI B31G 705- (Patrol) See V 706- (Leak survey) - leakage surveys must be conducted once a calendar year, not to exceed a 15 mo. interval - however, leakage surveys with a leak detector must be made when gas unodorized in class 3 location at least twice a year, not exceeding a 7½ mo. interval; class 4 locations 4 times each calendar year, not exceeding a 4½ mo. interval 711- (Repair-Gen) - take measures to protect public - leak, imperfection, or damages make permanent repair as soon as feasible 713- (Perm repair) - if feasible take out of service and repair by cutting out a cylinder and replacing pipe - if not feasible take out of service, repair by installing a split sleeve - reduce pressure, if pipeline not taken out of service, to a safe level during repair 715- (Weld repair) - if feasible take pipeline out of service and repair in accordance with 192.245 - weld may be repaired in service if weld not leaking, reduce pressure to 20% SMYS, grinding is limited so at least 1/8" thickness remains - if weld cannot be repaired, as above, install a full encirclement sleeve	

Cause of Failures	192 Requirements	
	Primary (1)	**Secondary** (1)
Corrosion Related Continued		
• Internal – IC	475- (General IC) - Corrosive gas can not be transported until the corrosive effect of the gas has been investigated and action taken to minimize corrosion - inspection of pipe removed, if IC is found, must determine effect of corrosion in adjacent pipe and replacement made as required - gas containing more than 0.25 grain in 100 cf may not be stored in pipe-type or bottle-type holders 477- (IC monitoring) - transportation of corrosive gas requires coupons, or other means to measure effectiveness of corrosion control, each coupon or other means of monitoring must be checked 2 times each calendar yr., but intervals not exceeding 7½ mos. 705- (Patrol) See V 706- (Leak survey) - leakage surveys must be conducted once a calendar year, not to exceed a 15 mo. interval - however, leakage surveys with a leak detector must be made when gas unodorized in a class 3 location at least twice a yr., not exceeding a 7½ mo. interval; class 4 locations 4 times each calendar yr., not exceeding 4½ mo. intervals	53(a)- (Materials) - able to maintain structural integrity 603- (Gen Oper) - operate in accordance with Subpart L - must keep records 613- (Surveil) - procedure for continuing surveillance of facilities to determine and take action for changes in O&M

Cause of Failures	192 Requirements	
	Primary (1)	**Secondary (1)**
Miscellaneous Equipment and Pipe		
• Gasket O-ring failure – GF	53(a)- Matls) - maintain structural integrity APP A-(Ref Spec) - incorporated by reference 273- (Gen joining) - must be designed and installed to sustain longitudinal pullout, or thrust caused by contraction or expansion, or by external, or internal loading - joint must be made by written procedures, proven by test, or experience - joint must be inspected for compliance 605- (Procedures) - manual of written procedures required, must include O&M activities, emergency response and abnormal operations 613- (Cont'd surveill) - procedure for continuing surveillance of facilities to determine and take action for changes in O&M 706- Leak survey) - leakage surveys must be conducted once a calendar yr., not to exceed a 15 mo. interval - however, leakage surveys with a leak detector must be made when gas unodorized in class 3 location at least twice a calendar yr., not exceeding a 7½ mo. interval, class 4 location 4 times a calendar yr., not to exceed a 4½ mos. interval	736- (Gas detect) - compressor building must have fixed gas detection and alarms unless building has 50% of upright side open, the station is unattended with 1000 hp or less - gas detection must monitor gas in air of more than 25% of lower explosive limit - detector must warn people inside and outside building - must be maintained and must include performance tests 749- (Vault maint) - must be inspected once ea. calendar yr., not exceeding 15 mos. interval - if gas is detected must be inspected for leaks and leaks must be repaired - ventilating equipment must be inspected for proper operation - cover must be inspected to assure no hazard to public 751-(Accid.Ignit) - when gas present in atmosphere; shall take steps to minimize danger of accidental ignition, such as, remove sources of ignition, provide fire extinguishers, no welding, or cutting, and post warning signs

Cause of Failures	192 Requirements	
	Primary (1)	**Secondary** (1)
Miscellaneous Equipment and Pipe (Continued)		
• Stripped threads/broken pipe/coupling fail – TSBPC	53(a) (Matls) APP A-(Ref Specs) - Maintain structural integrity - Incorporated by reference 103- (Design-Pipe) - pipe must be designed with sufficient wall thickness, or installed with adequate protection to withstand anticipated external pressures and loads that may be anticipated 143- (Design-Gen Req) - each component must withstand operating pressures and other anticipated loadings without impairment of serviceability based on unit stresses if design based on unit stresses is impractical design, may be based on pressure rating by manufacturer pressure testing that component or a prototype 273- (Gen joining) - must be designed and installed to sustain longitudinal pullout, or thrust caused by contraction or expansion, or by external, or internal loading - joint must be made by written procedures, proven by test, or experience - joint must be inspected for compliance 303- (Spec comply) - must be constructed in accordance with comprehensive written specifications or standards 305- (Insp-Gen) - each transmission pipeline constructed must be insp. for compliance 307- (Insp-Matls) - pipe and other component must be visually insp. on site of installation for damage	736- (Gas detect) - compressor building must have fixed gas detection and alarms unless building 50% of upright side is open, the station is unattended with 1000hp or less - gas detection must monitor gas in air of more than 25% of lower explosive limit - detector must warn people inside and outside building - detector must be maintained and must include performance tests 749- (Vault main) - must be inspected once ea. calendar yr., not exceeding 15 mos. intervals - if gas is detected must be inspected for leaks and leaks must be repaired - ventilating equip. must be inspected for proper operation - cover must be insp. to assure no hazard to public 751- (Accid.Ignit) - when gas present in atmosphere; shall take steps to minimize danger of accident ignition, such as, remove sources of ignition, provide fire extinguishers, no welding, or cutting, and post warning signs

Cause of Failures	192 Requirements	
	Primary [(1)]	**Secondary** [(1)]
Miscellaneous Equipment and Pipe (Continued)		
• Stripped threads/broken pipe/coupling fail – TSBPC (Continued)	605- (Procedures) - prepare and follow written procedures for O&M activity and emergency response. Also, must include procedures for abnormal operations 613- (Cont'd surveill) - procedures for continuing surveillance of facilities to determine and take action for changes in O&M 706- (Leak survey) - leakage surveys must be conducted once a calendar yr., not to exceed 15 mo. intervals - however, leakage surveys with a leak detector must be made when gas unodorized in class 3 location at least twice a calendar yr.; not to exceed 7½ mos. intervals; class 4 locations 4 times calendar yr., not to exceed 4½ mos. interval	
• Control/Relief equipment malfunction – MCRA	53(a)-(Matls) - maintain structural integrity APP A-(Ref Specs) - incorporated by reference 143- (Design-Gen Req) - each component must withstand operating pressures and other anticipated loadings without impairment of serviceability based on unit stresses - if design based on unit stresses is impractical, design may be based on pressure rating by manufacturer pressure testing that component or a prototype 169- (Pres limit device) - compressor station must have pressure relief or other protective device to ensure MAOP of station piping and equipment is not exceeded more than 10% - vents for relief valves must discharge to non-hazardous area	605- (Procedures) - prepare and follow written procedures for O&M activity and emergency response; also, must include procedures for abnormal operations 736- (Gas detect) - compressor building must have fixed gas detection and alarms unless building has 50% of the upright side open, the station is unattended with 1000 hp or less - gas detection must monitor gas in air of more than 25% of lower explosive limit - detector must warn people inside and outside building - detector must be maintained and must include performance tests 751- (Accid.Ignit) - when gas present in atmosphere; shall take steps to minimize danger of accidental ignition, such as, remove sources of ignition, provide fire extinguishers, not welding, or cutting, and post warning signs

Cause of Failures	192 Requirements	
	Primary (1)	**Secondary** (1)
Miscellaneous Equipment and Pipe (Continued)		
• Control/Relief equipment malfunction – MCRA (Continued)	199- (Pres rel design) - except for rupture discs, pressure limiting device must not corrode, valves not stick, able to check operation or leakage, noncombustible support, vent stack protected from water, snow, ice and venting to non-hazardous location, designed to prevent unauthorized operation that would isolate the relief device from pressure service 706- (Leak survey) - leakage surveys must be conducted once a calendar yr., not to exceed 15 mo. intervals - however, leakage surveys with a leak detector must be made when gas unodorized in cl. 3 location at least twice a cal. yr., not exceeding 7½ mo. intervals; cl. 4 location at least 4 times a cal. yr., not to exceed 4½ mo. intervals 731- (Insp/test at CS) - except for rupture disc, pressure relieving devises in compressor stations must be inspected and tested and operated periodically to determine that it opens at the correct set pressure - defective equipment must be promptly repaired or replaced or replaced - remote control shutdown device must be inspected and tested at least once each calendar year, at intervals not to exceed 15 months 739- (Insp/test-Regs) - pressure limiting station, relief device, and pressure regulating stations at intervals of 15 mos., but at least each calendar year subject to test and inspections to determine if in good mechanical condition, adequate capacity, reliability, correct set point, protected from dirt and liquids	

Cause of Failures	192 Requirements	
	Primary [(1)]	**Secondary** [(1)]
Miscellaneous Equipment and Pipe (Continued)		
• Control/Relief equipment malfunction – MCRA (Continued)	741- (Insp/test-Gauge) - distribution systems supplied by more than one district pressure regulating station must be equipped with telemetering or recording pressure gauge to monitor pressure - distribution system supplied by a single district pressure regulator must determine the necessity of installing telemeters or new gauges - indications of high or low pressure must be suspended and corrected 743- (Test relief dev) - if feasible relief valve must be tested for adequate capacity at least once a calendar year at intervals not to exceed 15 mos. - if a test is not feasible a review and calculation for each relieving device must be made at least once a year, not exceeding a 15 mos. interval - if insufficient capacity is found, a new or additional device must be installed to provide additional capacity	

Cause of Failures	192 Requirements	
	Primary (1)	**Secondary** (1)
Miscellaneous Equipment and Pipe (Continued)		
• Seal/pump packing failure – SPPF	53(a)- (Matls) - maintain structural integrity APP A-(Ref specs) - incorporated by reference 273- (Gen joining) - must be designed and installed to sustain longitudinal pullout, or thrust caused by contraction or expansion, or by external, or internal loading - joint must be made by written procedures, proven by test, or experience - joint must be inspected for compliance 357- (Meter install) - meter and regulator must be installed to minimize stresses - when close all-thread nipples are used, remaining wall must not be less than minimum wall thickness - lead or other easily damaged material may not be used - regulators that vent gas in operation must be vented to the atmosphere 605- (Procedures) - prepare and follow written procedures for O&M activity and emergency response. Also, must include procedures for abnormal operations 706- (Leak survey) - leakage surveys must be conducted once a calendar yr., not to exceed a 15 mo. interval - leakage surveys with a leak detector must be made when gas unodorized in cl. 3 location, at least twice a cal. yr., not to exceed 7½ mo. interval; cl. 4 location, 4 times a cal. yr., not to exceed 4½ mo. intervals	167- (Comp ESD) - except for unattended field compressors of 1000 hp or less must have an emergency shutdown system 171- (Comp addnl safety) - must have fire protection facilities - must have overspeed protection on prime mover and compressor (except electric motors) - must have shutdown or alarm for inadequate cooling or lubrication - gas engines muffler must have slots or holes in baffles 736- (Gas detect) - compressor building must have fixed gas detection and alarms unless bldg. has 50% of the upright side open, the station is unattended with 1000 hp or less - gas detection must monitor gas in air of more than 25% of lower explosive limit - detector must warn people inside and outside bldg. - detector must be maintained and must include performance tests 751- (Accid. Ignit) - when gas present in atmosphere; shall take steps to minimize danger of accidental ignition, such as, remove sources of ignit., provide fire extinguishers, no welding, or cutting, and post warning signs

Cause of Failures	192 Requirements	
	Primary (1)	**Secondary** (1)
Miscellaneous Equipment and Pipe (Continued)		
• Wrinkle bend or buckle – WBB	159- (Flexibility) - must be designed to prevent thermal expansion or contracting from causing excessive stresses 161- (Anchors/supp) - pipelines must have enough anchors and supports to prevent undue strain on connected equipment, resist longitudinal forces, prevent excessive vibration. - exposed pipeline must have enough supports or anchors to protect pipe from maximum end force caused by internal pressure or additional forces caused by temperature expansion, or contraction, or weight of pipe - supports and anchors on exposed pipelines must be durable, noncombustible material; and allow free expansion and contraction, provision for service conditions, and movement will not disengage equipment - exposed pipelines over 50% SMYS must not be welded to structural support, supports must be encirclement, if welded to pipe must be continuous over entire circumference - underground pipeline must have enough flexibility or be anchored - branch connection must have firm support	605- (Procedures) - manual of written procedures required, must include O&M activities, emergency response and abnormal operations 706- (Leak survey) - leakage surveys must be conducted once a year, not to exceed a 15 mo. interval - however, leakage surveys with a leak detector must be made when gas unodorized in class 3 locations at least twice a year, not exceeding a 7½ mo. inter- val; class 4 locations 4 times each calendar yr., not exceeding a 4½ mo. interval

Cause of Failures	192 Requirements	
	Primary [(1)]	**Secondary [(1)]**
Miscellaneous Equipment and Pipe (Continued)		
• Wrinkle bend or buckle – WBB	315- (Wrinkle bends) - wrinkle bends not allowed on pipe to operate 30% or more, SMYS - wrinkle bends must not have sharp kinks - wrinkles must be at least a distance of one pipe diameter measuring along the crotch - pipe 16", or larger, diameter must not have deflection more than 1½" per wrinkle - longitudinal seams must be as near as practical to the neutral axis 317- (Hazard prot) - protect from washouts, floods, unstable soil, slides, or other hazards	
• Miscellaneous – MISC		605-(Procedures) - manual of written procedures required, must include O&M activities, emergency response and abnormal operations

Cause of Failures	192 Requirements	
	Primary [(1)]	**Secondary** [(1)]
Incorrect Operation		
• Incorrect operation Company procedure – IO	199- (Pres relief design) - except for rupture discs, pressure limiting device must not corrode, valves not stick, able to check operation or leakage, noncombustible support, vent stack protected from water, snow, ice and venting to non-hazardous location, designed to prevent unauthorized operation that would isolate the relief device from pressure service 605- (Procedures) - manual of written procedures required, must include O&M activities, emergency response and abnormal operations 615- (Emerg plan) - establish written procedures to minimize hazards 805- (Qualification) - each operator shall have and follow a written qualification program	53(a)-(Materials) - maintain structural integrity APP A-(Ref Specs) - incorporated by reference 143-(Design-Gen) - each component must withstand operating pressures and other anticipated loadings without impairment of serviceability based on unit stresses - if design based on unit stresses is impractical design may be based on pressure rating by manufacturer pressure testing that component or a prototype 613-(Cont surveil) - procedure for continuing surveillance of facilities to determine and take action for changes in O&M 751-(Accid.ignit) - when gas present in atmosphere; shall take steps to minimize danger of accidental ignition, such as, remove sources of ignit., provide fire extinguishers, no welding, or cutting, and post warning signs

Cause of Failures	192 Requirements	
	Primary (1)	**Secondary** (1)
Weather Related		
• Cold Weather – CW	53(a) – Matls APP A-(Ref Specs) - Maintain structural integrity - Incorporated by Reference	141- (Pipe Design) - Scope, design and installation reqmt. of components and reqmts. against accidental overpressure 159- (Flexibility) - must be designed to prevent thermal expansion or contraction from causing excessive stresses 225- (Gen Welding) - welder using qualified procedures required. Procedures requires destructive test 303- (Spec.Comp) - Construction requires comprehensive written specification or standards 605- (Proced Manual) - Manual of written procedures required, must include O&M activities, emergency response and abnormal operations - Manual review once each calendar year, intervals not more than 15 months 615- (Emerg Plan) - establish written procedures to minimize hazards

Cause of Failures	192 Requirements	
	Primary [(1)]	**Secondary [(1)]**
Weather Related (Continued)		
• Lightning – LIGHT	467- (Elect. isol) - must electrically isolate from other structures or interconnect cathodically protected as a unit - where unusual risk of lightning pipeline must be provided pipeline must be provided with protection and measures to protect insulating devices 465- (CP monitor) - CP once a yr (not exceeding 15 mos. interval) rectifier, 6 times calendar yr (not exceeding 2½ mos. interval) - interference bond, 6 times calendar year (not exceeding 2½ mo. interval) - unprotected lines, 3 yrs and apply Cathodic protection if active corrosion is found - separately protected short sections may be inspected over 10 yrs at 10% per year	605- (Proced Manual) - manual of written procedures required, must include O&M activities, emergency response and abnormal operations 613- (Contd surveill) - procedure for continuing surveillance of facilities to determine and take action for changes in O&M 615- (Emerg Plan) - establish written procedures to minimize hazards

Cause of Failures	192 Requirements	
	Primary (1)	Secondary (1)
Weather Related (Continued)		
• Heavy rain or floods HRF	103- (Gen Design) - Pipe must be designed with sufficient wall thickness, or installed with adequate protection to withstand anticipated external pressures and loads that may be imposed 159- (Flexibility) - must be designed to prevent thermal expansion or contracting from causing excessive stresses 179- (Trans vales) - valves must be spaced 2½ mi. in Class 4, 4 mi. in Class 3, 7½ mi. Class 2, 10 mi. in Class 1 - must be accessible and protected from tampering and damage - must be supported to prevent settling or movement of pipe - must have blowdown except offshore 189- (Vaults) - must be designed to minimize entrance of water - must not connect drain to any underground structure - electrical conform to Class 1, Group D of NEC ANSI/NFPA 70 317– (Hazard prot.) - from washouts, floods, unstable soil , and slides, or other hazards - protect from traffic - protect risers (offshore) 327– (Cover.) - 1 - 30” soil, 18” rock - Class 2, 3, 4 – 36” soil, 24” rock - ditches, public roads, and railroads – 36” soil, 24” rock	303- (Spec comply) - pipeline must be constructed in accordance with comprehensive written specifications or standards 605- (Proced manual) - must prepare and follow a manual of written procedures for O&M activities and emergency response. Must include abnormal operations 613- (cont surveill) - procedures for continuing surveillance of facilities to determine and take action for changes in operations and maintenance 615- (Emerg plan) - establish written procedures to minimize hazards 751- (Accid ignit) - when gas present in atmosphere; shall take steps to minimize danger of accidental ignition, such as, remove sources of ignition, provide fire extinguishers, no welding, or cutting , and post warning signs

Cause of Failures	192 Requirements	
	Primary (1)	**Secondary** (1)
Weather Related (Continued)		
• Heavy rain or floods HRF (Continued)	705- (Patrol) - should have patrol program to observe service condition - frequency not longer than: Class / Hwy. & RR X-ing. / All other places 1, 2 / 7½ mos.. at least twice calendar yr. / 15 mos., at least once calendar yr. 3 / 4½ mos., at least 4 times each calendar yr. / 7½ mos., at least twice each calendar yr. 4 / 4½ mos., at least 4 times each calendar yr. / 4½ mos., at least 4 times each calendar yr. - Methods can be walking, driving, flying, or other means	
Unknown		
		605- (Procedures) - manual of written procedures required, must include O&M activities, emergency response and abnormal operations - manual review once each calendar year, interval snot more than 15 mos.

Cause of Failures	192 Requirements	
	Primary (1)	**Secondary** (1)
Manufacturing Related Defects		
• Defect pipe seam – DPS	53(a)- (Materials) - maintain structural integrity APP A- (Ref Specs) - Incorporated by Reference 55- (Steel Pipe) - new pipe is qualified for use in accordance with requirements of this paragraph 113- (Joint factor) - the acceptable longitudinal joint factors to be used in the design formula are listed if the joint factor can not be determined, the joint may not exceed that designed "other" in the table 503- (Test Req) See PDP 713- (Perm repair of imperfections) See EC 715- (Perm repair of welds) See EC	313- (Bends/elbows) - field bends must not impair serviceability of pipe, must have smooth contour, free from buckling, cracks, or damage - longitudinal weld, when practical be near neutral axis 605- (Procedures) - manual of written procedures required, must include O&M activities, emergency response and abnormal operations - manual review once each calendar year, interval snot more than 15 mos. 706- (Leak survey) - leakage surveys must be conducted once a calendar year, not to exceed a 15 mo. interval - however, leakage surveys with a leak detector must be made when gas unodorized in Class 3 location at least twice a year, not exceeding a 7½ mo. interval; Class 4 locations 4 times each calendar year, not exceeding a 4½ mo. interval
• Defect pipe seam – DPS	717- (Perm repair of leaks) - onshore field repair of leaks must be repaired by cutting out a cylinder of pipe and replacing with pipe of similar or greater design if it is feasible to take the line out of service - if not feasible to remove from service, install a full encirclement split sleeve - leak due to corrosion pit, can be repaired by bolt-on-leak clamp - leak due to corrosion pit and operating less than 40,000 (SMYS), a steel plate with rounded corners can be welded over corrosion pit - offshore or other underwater pipelines are repaired by full encirclement sleeve	

Cause of Failures	192 Requirements	
	Primary (1)	**Secondary** (1)
Manufacturing Related Defects (Continued)		
• Defective pipe – DP	53(a)- (Materials) - maintain structural integrity APP A- (Ref Specs) - Incorporated by Reference 55-(Steel pipe) See above 309- (Steel pipe repair) See above 503- (Test Req) See PDP 713- (Perm repair of imperfections) See EC 715- (Perm repair of welds) See EC 717- (Perm repair of leaks) See DPS	605- (Procedures) - manual of written procedures required, must include O&M activities, emergency response and abnormal operations - manual review once each calendar year, interval snot more than 15 mos. 706- (Leak survey) - leakage surveys must be conducted once a calendar year, not to exceed a 15 mo. interval - however, leakage surveys with a leak detector must be made when gas unodorized in Class 3 location at least twice a year, not exceeding a 7½ mo. interval; Class 4 locations 4 times each calendar year, not exceeding a 4½ mo. interval

Cause of Failures	192 Requirements	
	Primary (1)	**Secondary (1)**
Welding/Fabrication Related		
• Defective pipe girth weld – DGW	225- (Welding-Gen) - qualified welder using qualified procedures required. Procedures requires destructive test 151-(Welding qual) - Welders must be qualified in accordance with Sect. 3 of API Std. 1104, or Sect. IX of ASME BPVC - welder may qualify to weld pipe under 20% SMYS by acceptable test in Sect. I of Appdx. C, however, a welder must qualify by making a successful test under Sect. II of Appdx. C to weld a service line to a main 229- (Welder-Limits) - no welder qualified on nondestructive testing may weld compressor station pipe and components - no welder may weld with a particular welding process unless, within the proceeding 6 calendar months, he has welded with that process 231- (Weather prot) - welding operation must be protected from weather conditions that would impair the quality of the completed weld 233- (Miter joints) - miter joint operated at 30% of SMYS, or more, may not deflectmore than 3° - miter joint operating less than 30% of SMYS, but more than 10% of SMYS may not deflect more than 12½° and must be more than one pipe diameter from another miter joint - miter joint operating less than 10% of SMYS, may not deflect more than 90° 235- (Weld prepare) - surface must be clean - pipe or component must be properly aligned - alignment must be maintained for applying root bead	605- (Procedures) - manual of written procedures required, must include O&M activities, emergency response and abnormal operations - manual review once each calendar year, intervals not more than 15 mos. 706- (Leak survey) - leakage surveys must be conducted once a calendar yr., not to exceed 15 mo. intervals - however, leakage surveys with a leak detector must be made when gas unodorized in cl. 3 locations at least twice a cal. yr., not to exceed 7½ mo intervals; class 4 location 4 times a cal. yr., not to exceed 4½ mo. intervals 751- (Accid.ignit) - when gas present in atmosphere; shall take steps to minimize danger of accidental ignition, such as, remove sources of ignition, provide fire extinguishers, no welding, or cutting, and post warning signs

Cause of Failures	192 Requirements	
	Primary (1)	**Secondary** (1)
Welding/Fabrication Related (Continued)		
• Defective pipe girth weld – DGW (Continued)	241- (Insp/test welds) - visual inspection must be conducted to determine if performed in accordance with welding procedure and that weld is acceptable under Sect. 6 of API Std. 1104 - welds to be operated at 20% or more of SMYS must be non-destructively tested in accordance with AP 1104, unless they are visually inspected and approved by a qualified welding inspector and the pipe is less than 6”, or the pipeline operates at less than 40% of SMYS and welds are so limited in number that nondestructive testing is impractical - the acceptability of a weld nondestructively tested or visually inspected is determined according to Sect. 6 API 1104 243- (Weld NDT) - nondestructive testing must be by any process, other than trepanning that will indicate defects in the weld integrity - nondestructive testing must be by written procedures by persons qualified and trained in the established procedures and equipment used - procedures must be established for proper interpretation - when nondestructive testing is required the percentages of butt welds selected at random each day, must the tested over entire circumference Class 1 - 10% Class 2 - 15% Class 3 & 4 and at x-ing of major or navigable rivers, offshore, within RR or public highways, R-O-W, including tunnels, bridges and overhead road x-ing is 100%, unless impracticable 90% is required - at pipeline tie-ins, including pipe replacements, require 100% testing - nondestructive testing records showing location must be retained for life of pipeline	

Cause of Failures	192 Requirements	
	Primary (1)	**Secondary (1)**
Welding/Fabrication Related (Continued)		
• Defective pipe girth weld – DGW (Continued)	245- (Weld defect rem) - unacceptable welds must be removed, or repaired, except welds offshore installed from a pipeline vessel, a weld must be removed with a crack more than 8% of weld length - weld repaired must have defect removed down to sound metal - after repair the weld must be inspected to ensure acceptability - repair of crack, or defect in a previously repaired area must be done in accordance with written qualified procedures 309- (Steel pipe repair) - imperfections or damage that impair serviceability of pipe must be repaired or removed - repairs by grinding must not reduce wall thickness below tolerance in specs. or nominal wall required in design pressure - dents in pipe operated at 20%, or more, SMYS must be removed if the dent contains a scratch, gouge, groove, or arc burn. Also, dents that affect a longitudinal weld or circumferential weld - in pipe operating at 40% or more of SMYS a dent more than ¼" , 12¾" diameter pipe, or a 2% dent in 12¾" diameter pipe, must be removed - in pipe operating at 40%, or more, SMYS an arc burn must be removed, or repaired - a gouge, groove, arc burn, or dent may not be repaired by insert patching, or by pounding out - each gouge, groove, arc burn, or dent must be cut out as a cylinder and replaced with pipe	

Cause of Failures	192 Requirements	
	Primary (1)	**Secondary** (1)
Welding/Fabrication Related (Continued)		
• Defective pipe girth weld – DGW (Continued)	503- (Test Req) - no person may operate a new segment of pipeline, or return to service a segment of pipelines that has been relocated, or replaced - it must first be tested in accordance with this Subpart and 192.619 to substantiate the MAOP - testing tie-ins are not required, but a non-welded joint must be leak tested at its operating pressure 715- (Weld repair) - unacceptable welds must be repaired in accordance with weld repair procedure in 192.245 - if the weld can not be repaired by these procedures, it must be repaired by installing a welded split sleeve 805- (Quailif program) - each operator shall have and follow a written qualification program	
• Defective fabrication weld – DFW	143- (Design-Gen Req) - each component must withstand operating pressures and other anticipated loadings without impairment of serviceability based on unit stresses - if design based on unit stresses is impractical, design may be based on pressure rating by manufacturer pressure testing that component or a prototype 151-(Tapping) - mechanical fitting used for hot tap must be designed for at least operating pressure	605- (Procedures) - manual of written procedures required, must include O&M activities, emergency response and abnormal operations - review once each calendar year, intervals not more that 15 mos. 706- (Leak survey) - leakage surveys must be conducted once a calendar year, not to exceed a 15 mo. interval - however, leakage surveys with a leak detector must be made when gas unodorized in class 3 location, at least twice a year, not exceeding a 7½ mo. interval; class 4 locations 4 times each calendar yr., not to exceed a 4½ mo. interval 751- (Accid. Ignit) (see above)

Cause of Failures	192 Requirements	
	Primary (1)	**Secondary** (1)
Welding/Fabrication Related (Continued)		
• Defective fabrication weld – DFW (Continued)	153- (Fab. Component) - except for branch connections and assemblies of standard pipe joined by circumferential welds, each component whose strength can not be determined must be established in accordance with para. UG-101 of Sect. VIII, Div. 1 of ASME BPVC - prefabricated units that use plate and longitudinal seams must be designed, constructed and tested in accordance with Sect. 1, Sect. On VIII, Div. 2 of ASME BPVC, except manufactured butt fitting, pipe produced and tested under specification list in Appdx. B - prefabricated units certified by manufacturer to being tested twice maximum pressure to which it will be subjected - orange-peel bull plugs and orange-peel swages may not be used over 20% of SMYS of the pipe - except for flat closures designed in accordance with Sect. VIII of the ASME PBVC, flat closures and fish tails may not be used on pipe operating at 100 psi, or more, or more than 3” 155- (Branch connect) - branch connections made to pipe either single, or in a header, or manifold must be designed to account the stress in the remaining pipe wall due to the opening(s), the shear stresses caused by the pressure acting on the branch opening and external loading due to thermal movement, weight and vibration 225- (Welding-Gen) See DGW 227- (Welder qual) Welder to qualify by API in ASME Stds. 229- (Welder limits) See DGW	

Cause of Failures	192 Requirements	
	Primary (1)	**Secondary** (1)
Welding/Fabrication Related (Continued)		
• Defective fabrication weld – DFW (Continued)	231- (Weather prot) See DGW 233- (Miter joints) See DGW 235- (Weld prepare) See DGW 241- (Insp/test welds) See DGW 243- (Weld NDT) See DGW 245- (Weld defect rem) See DGW 309- (Steel pipe repair) See DGW 503- (Test req) See DGW 715- (Weld repair) See DGW 805- (Qualif. Program) See DGW	

Cause of Failures	192 Requirements	
	Primary [(1)]	Secondary [(1)]
Outside Forces		
• Earth movement – EM	103- (Gen Design) - Pipe must be designed with sufficient wall thickness, or installed with adequate protection to withstand anticipated external pressures and loads that may be imposed 159- (Flexibility) - must be designed to prevent thermal expansion or contraction from causing excessive stresses 161- (Support/anchor) - pipelines must have enough anchors and supports to prevent undue strain on connected equipment, resist longitudinal forces, prevent excessive vibration. - exposed pipeline must have enough supports or anchors to protect pipe from maximum end force caused by internal pressure or additional forces caused by temperature expansion, or contraction, or weight of pipe - supports and anchors on exposed pipelines must be durable, non- combustible material; and allow free expansion and contraction, provision for service conditions, and movement will not disengage equipment - exposed pipelines over 50% SMYS must not be welded to structural support, supports must be encirclement, if welded to pipe must be continuous over entire circumference - underground pipeline must have enough flexibility or be anchored - underground branch connection must have firm support 317- (Hazard prot) - protect from washouts, floods, unstable soil, and slides, or other hazards 613- (Surveil) - procedure for continuing surveillance of facilities to determine and take action for changes in O&M	53(a)- Matls) - able to maintain structural integrity under temperature and other environmental conditions that may be anticipated 603- (Gen Oper) - operate in accordance with Subpart L - must keep records 605- (Proced manual) - prepare and follow written procedures for O&M activity and emergency response; also, must include procedures for abnormal operations

Cause of Failures	192 Requirements	
	Primary (1)	**Secondary** (1)
Outside Forces (Continued)		
• Earth movement – EM (Continued)	614- (Dam.Prevent) - written program to prevent damage from excavation activities - participation in one call system 705- (Petrol) See V 706- (Leak survey) - leakage surveys must be conducted once a calendar year, not to exceed a 15 mo. interval - however, leakage surveys with a leak detector must be made when gas unodorized in Class 3 location at least twice a year, not exceeding a 7½ mo. interval; Class 4 locations 4 times each calendar	
Environmental Cracking		
SCC – SCC	459- (Corr.exam) - examine pipe when exposed for corrosion, if found, take remedial action. Also determine extent of corrosion 461- (Ext.corr.) - properly applied coating, inspected for damage	53(a)- (Matls) - able to maintain structural integrity 603- (Oper – Gen) - operate in accordance with Subpart L - must keep records 605- (Proced manual) - prepare and follow written procedures for O&M activity and emergency response. Also, must include procedures for handling abnormal operations

Discussion on Meaning and Intent of 49 CFR 192.613

Paragraph 192.613 is viewed by some operators as a requirement to have a set of eyes on the pipeline on a "continuing" basis. This is understandable given the definition of "surveillance" in the dictionary, i.e., "to watch over." However, if one looks at the list of things in paragraph 192.613(a) that need to be considered when "watching over" the pipeline, it's evident, that it is not a visual examination of the physical facilities that the rule is talking about. This is confirmed by reading the B31.8 Code section 850.5 (1968 edition), the source text of paragraph 192.613. The text of these two are cited below:

> ***192.613 Continuing Surveillance.***
> (a) Each operator shall have a procedure for continuing surveillance of its facilities to determine and take appropriate action concerning changes in class location, failures, leakage history, corrosion, substantial changes in cathodic protection requirements, and other unusual operating and maintenance conditions.
>
> (b) If a segment of pipeline is determined to be in unsatisfactory condition but no imminent hazard exists, the operator shall initiate a program to recondition or phase out the segment involved, or, if the segment cannot be conditioned or phased out, reduce the maximum allowable operating pressure in accordance with 192.619(a) and (b).
>
> ***850.5 Continuing Surveillance of the Pipeline. (B31.8 Code – 1968)***
> As a means of maintaining the integrity of its pipeline system each operator shall have a procedure for continuing surveillance of its facilities. Studies shall be initiated and appropriate action taken when unusual operating and maintenance conditions occur such as failures, leakage history, drop in flow efficiency due to internal corrosion or substantial changes in cathodic protection requirements.
>
> If such studies indicate that the facility is in unsatisfactory condition, but no imminent hazard exists requiring immediate action, a planned program to recondition or phase out such facility shall be initiated. If such facility cannot be reconditioned or phased out, the maximum allowable operating pressure shall be reduced commensurate with the requirements described in 845.22(c) of this Code.

Based on the preamble discussions in the Notice of Proposed Rulemaking and the Final Rulemaking of the original regulations, it is further evident that OPS did not change the intent of the source text (B31.8). In the rulemaking process, OPS stated that, unless they specifically identified a substantive change, the intent of the B31.8 Code sections corresponding to the rule was maintained. In the preamble of the Final Rule, it is clear that OPS did not change the intent of what the B31.8 Code meant by *"continuing surveillance."* However, OPS did change the list of the items to be considered. It explained that *"drop in flow efficiency due to internal corrosion"* was deleted because drops in flow efficiency are not necessarily a result of internal corrosion. They replaced this with *"corrosion."* OPS also noted that it added, *"changes in class location"* to the list (without discussion of why.)

If the premise is accepted that the original B31.8 intent was maintained, then it is much clearer in reading paragraph 850.5 that the unusual conditions are manifested by observations over time (failures, leakage history, drop in flow efficiency, and substantial changes in cathodic protection requirements. The observations may include patrols, surveys, inspections, maintenance, and tests, each of which are required in other parts of the Code (same for Part 192.) It was intended that the operator combine observations made over time to see if there is indication of an overall problem that the individual observations would miss. (Note that problems discovered at individual observations need to be addressed under specific requirements of the Code and the regulations.) This is a process that continues as additional observations are collected. If a review of the combined (or integrated) data suggests a potential unusual operating condition, a study to determine whether the problem suggests a significant risk to the integrity is required. If concluded that it is significant, then the operator must establish a program to take action to restore the integrity of the system, if an imminent hazard does not exist. This rule, therefore, is a performance element of an integrity management program.

If it were intended that continuing surveillance in paragraph 613 was an ongoing visual observation of the pipeline, then the list of things being watched do not make sense. Through a singular observation, one cannot see changes in class location (although one might see a change in house count.) One generally does not see failures in one observation (although one might see a singular failure.) One does not see leak history in a singular observation (history occurs over time). Although one may see a change in cathodic protection requirements in one observation, substantial changes generally occur over time.

Consider that Part 192 has specific requirements regarding patrols, leakage surveys, cathodic protection monitoring, inspections of pipe and coating, inspections of safety equipment, etc. These are performed at specified intervals. Consider also that Part 192 has specific requirements for what to do in the event that any of these individual observations suggest a problem. None of these are paragraph 613.

Why would paragraph 192.613 be used to mandate the very same observations required in other parts of the regulation? There is no reason because it isn't a redundant requirement, nor is it a general requirement because of its placement in the regulations. It's a separate requirement on its own. Here is a list of examples of some of the things that could be picked up under a continuing surveillance program (as understood in paragraph 192.613)

- An operator notes that on a particular segment of pipeline, he has had to increase the CP each of the last several years because of low readings. A study may conclude that the coating on that segment is deteriorating and needs to be reconditioned.
- An operator has noted that numerous inspections on pipe having a certain vintage and kind of coating indicate high occurrence of disbondment and shielded corrosion. A study may conclude that the operator will need to establish a program to locate and replace this coating throughout his system.
- An operator notes that on a particular part of his system, there appears to be an unusual number of leaks. A study may conclude that there is a lot of shielded corrosion occurring and that the coating needs to be replaced.

- An operator notes that valve operators made by XYZ have required an unusual amount of maintenance each of the last several years. A study may find that the maintenance indicates that the operators are near the end of their useful life and may need replacement or overhaul.
- An operator notes that overpressure protection devices of a certain make continually do not hold their sets between inspections. A study may conclude that this make of valves was not suited for the application and that these valves need to be replaced to avoid a potentially significant overpressuring.
- An operator notes over recent years cracks appearing in numerous weldolets on the discharge side of compressor engines. A study finds that a common design used in the discharge header piping did not adequately compensate for pulsation and that a program to modify the headers at all of these locations was needed.

These are examples of industry's interpretation and implementation of paragraph 613, making it, in effect, an integrity management plan in and of itself. Therefore, paragraph 192.613 is not listed in the rules section of the threats to integrity table for those threats that are discoverable with one observation (e.g., third party damage prevention – which is a patrolling issue). Other threats (e.g., certain corrosion problems) can and are discovered under paragraph 192.613. Wherever else one can discover a threat through the integration and analysis of data, paragraph 192.613 should be listed.

APPENDIX B

NATURAL GAS PIPELINE INDUSTRY RESEARCH & DEVELOPMENT PIPELINE INTEGRITY & SAFETY

The United States natural gas pipeline industry has a long history of dedication to justifying the public trust in maintaining pipeline integrity and safety. This dedication has been self-imposed by the industry's public consciousness and own economic self-interest. It is clear from the record of many decades that the correct philosophy of dependable and safe operation is entirely consistent with the fiduciary responsibility associated with the management of financial resources. It is this industry culture that provides the commitment to support the research and technology development necessary to solve industry problems and to address unmet needs. This commitment has been implemented in many ways, both large and small. Two very large and visible programs are contained in the work of Pipeline Research Council International (PRCI) and Gas Research Institute (GRI).

In 1952, the natural gas pipeline industry created PRCI to plan and coordinate a program in response to the issue of long-running brittle fractures. Given the likely extent of this serious threat to system integrity, and the fact that to identify it and stop it would be cost prohibitive to individual companies, a collaborative, voluntary funding approach was developed. The capability of this approach was clearly proven. This voluntary R&D organization provided the means to detect and prevent this systemic brittle fracture problem.

The structure, funding formula, and focus of PRCI have undergone change over the years, including the emphasis today on applied technologies rather than basic research. The vast majority of the work of PRCI assures system viability and reliability by identifying the problems affecting system integrity and the solutions to those problems. Pipeline industry guidance and support has been critical since GRI was established in 1976. GRI emphasizes more advanced technology projects and longer term research objectives. GRI's pipeline industry advisors and corporate management provide input to the planning process to ensure that program elements are balanced and meet at least one of six criteria:

Enhance health and safety
Increase gas system reliability
Enhance environmental quality
Lower gas industry operating and maintenance costs
Increase gas supply from emerging resources
Increase efficiency of use

In the past ten years, the natural gas pipeline industry has invested over $100 million through PRCI and GRI in safety related research. Much of this work is now embodied in ASME Standards such as B31, or NACE Corrosion Control Standards and available in publications such as the GRI Guide for Locating and Using Industry Research, GRI-00/0189. This pipeline model for technology development has produced significant technology breakthroughs under many technical subjects. Here is a partial listing of topics:

- External Corrosion*:* Coatings; Cathodic Protection (CP); Current Effects; Remaining Strength, Hydrogen Cracking,
- Internal Corrosion: Management of Microbiologically Influenced Corrosion (MIC), Corrosivity of CO_2, H_2S etc separately and combined, IC needs analysis,
- *External Force Impacts*: Prevention, Mitigation, Detection, Characterization & Assessment, and Remediation of 3-rd Party Damage; Avoiding Dynamite Blasting Damage in the right of way; Remote and Direct Measurement of Land Movement, Design for Earthquake and Soil Movement,
- *Failure Mechanics*: Ductile Fracture and Arrest, Toughness, Gas Decompression Driving Forces, Cracking; Strain, Crack Arrestor Designs
- *Metallurgy*: Steel Chemistries for Improved Toughness & Strength; Ductile Fracture; Dents & Defects, Hard Spots, Composite Pipe, Mill Quality Dests C_{vn}, DWTT, PCDWTT,
- *Non-destructive Testing*: External and Internal for Welds (radiography, ultrasonics); ERW Pipe; Pigging; Hydrostatic Testing, Process Control.
- *Components & Fittings*: Repair Techniques; Strength & Stress Reduction, Hot Tap Procedures.
- *Stress Corrosion Cracking (SCC)*: Metallurgical; Environmental; High & Low p-H
- *Welds & Welding*: Techniques, Mill and Field Processes & Procedures; Defects; Inspection
- *Non Intrusive Inspection*: Close Interval Survey Criteria, Voltage and Magnetic Measurement Technologies such as the Current Mapper, Direct Current Voltage Gradient,
- *Repair*: Pipeline Repair Manual, ClockSpring™, Welded Steel Sleeves, Direct Deposit Welding, In-Service Pipeline Lowering,
- *Gas Dispertion and Combustion*: Software such as DEGADIS, confined and unconfined combustion of natural gas and natural gas liquids
- *Rights of Way*: Hydrotest Water Acquisition and Disposal, Preserving Microhabitats, Mitigation of Spills, Site Restoration,

Key Pipeline Technologies in Use

The following work, focusing on selected technology development brought on line during the 1990's, presents a sampling of integrity-relevant work. In nearly every case, the work cited represents the culmination of several related and integrated projects, typically produced over a period of time.

Corrosion

- **Development of Coupons to Read Off-Potentials of Pipelines**
  Since 1992, the pipeline industry has devoted a large effort to investigate the effectiveness of using steel coupons buried on the outside of the pipeline to monitor the effectiveness of cathodic protection. The coupon technology has introduced superior methods to measure the adequacy of cathodic protection systems without the inefficient interruption of CP current protecting the pipelines. The coupons have also proved a valuable tool for investigation of many other CP problems including interference stray direct currents (DC) from mining and railways, telluric currents, AC interference, and long line detection currents encountered in the depolarization of pipeline systems.

- **Alternating Current (AC) Prediction & Mitigation Techniques**
  AC mitigation is becoming a major problem as pipeline right-of-way (ROW) is harder to acquire, and pipelines are subsequently forced to share power corridors with high voltage AC transmission lines. This has created incidences where significant voltages have been observed on pipelines in the ROW, raising concerns for both personal safety and system integrity. The pipeline industry through collaborative work completed development of a user friendly software package in 1997 to assist the pipeline operators in resolving two-thirds of the situations while sharing the ROW with AC voltage lines.

- **Assuring the integrity of corroded pipe**
  The RSTRENG assessment methodology, which was recognized in the federal pipeline safety regulations in 1996, has been the primary means for determining the remaining strength of corroded pipe, and as such is critical for pipe repair and remediation decisions made both within and without a risk assessment program. This has already been incorporated in ASME's B31G code and referenced in 49 CFR 192 and 195.

- **Cathodic Protection (CP)**
  There have been major accomplishments in the area of cathodic protection, including: CP Criteria - The pipeline industry devoted over $1 million and thousands of hours of research to investigate the CP Criteria to assist NACE (National Association of Corrosion Engineers) with the rewrite of RP0169. All of the changes are already incorporated in NACE standards and many of the changes were written into the Department of Transportation (DOT) code 49 CFR 192 in 19996, to ensure pipeline integrity for the pipeline systems.

- **Internal Corrosion Models**
  Some of the major results of the work on internal corrosion are: Models to estimate the corrosion rates with normal pipeline gas and liquid contaminants and expected operating conditions; A Risk Assessment Program to assist pipeline operators to choose the most effective internal corrosion mitigation action plans; A major study on the Management of Microbiologically Induced Corrosion (MIC). This research has been the basis for on-going studies on detection, identification, and mitigation of corrosive environments caused by MIC.

- **Pipeline Current Mapper/Stray Current Mapper**
  The Pipeline Current Mapper (PCM) and the pending Stray Current Mapper (SCM) were developed to overcome some of the limitations and complexity of existing CP survey techniques. Limitations of existing CP system troubleshooting techniques include:

  1. Labor intensive (multiple connections to pipeline)
  2. Requires highly trained/skilled operator
  3. Subject to user interpretation and error

  The PCM has been implemented by over 20 US operators since its introduction in 1997.

<u>**Internal Corrosion**</u>

- **Microbiologically Induced Corrosion (MIC)**
  MIC has been recognized as a major concern for internal corrosion on the gas pipeline infrastructure, especially in the gathering and storage fields. A multi-year study has laid the basic groundwork for understanding many of the MIC issues, and is a basis for much of the research today. Another major undertaking is the development of a benign methodology to control the bacteria. Three technologies were investigated, and presently GTI is pursuing a patent on one of the technologies. Research was performed on the susceptibility of certain steel microstructures to MIC. The report is in draft form, and members are already applying knowledge of the report.

- **Gas and Water Chemistry**
  Many corrosive contaminants (CO2, H2S, and oxygen) are either produced with the gas, or are introduced into the gas stream through operations. Whenever water is present to act as an electrolyte, these contaminants often cause corrosion. A detailed matrix of different combinations of gas contaminants and fluids was developed, to start a testing program to determine the corrosivity of these different combinations. The corrosion rates were determined by placing coupons in pressurized vessels to simulate pipeline conditions. Graphs and algorithms for internal corrosion rates were developed in this project for different mixtures of contaminants, and are being used by operators today. A Risk Assessment program has also been written using the same logic as applied in the testing.

- **Monitoring Internal Corrosion**
  Knowing if and when internal corrosion is occurring will help the corrosion engineer and technicians improve their ability to control internal corrosion. The industry has co-funded work with DOE and marketing partner to develop a probe which can detect active pitting as it

occurs. The probe is superior to existing technologies such as polarization probes that can loose sensitivity under normal operating conditions. This probe is now in the Beta testing phase.

- **Research Needs for the Future**
  The corrosion committee for PRCI and GTI recognized that internal corrosion has many interactions (including bacteria), which create the whole internal corrosion process. Recognizing this, they embarked on a "Gap Analysis" to study what has been done to date, and what the needs are for future research to fill the missing gaps of research. The result is a very focussed multi-year plan for future research. The study identified 9 gaps for future research, of which two are already under study.

<u>External Forces and Loads</u>

- **External Force**
  External force which includes 3 rd party damage, incorrect operations, and "acts-of-God", like floods and landslides, are the most prevalent root cause in the pipeline incidents reported to DOT. Studies of the One Call System, sources of External Force Damage and methodologies to prevent Excavation Damage have recently been completed to identify gaps in the systems that thereby minimize the incident rate. In 1997, spacing of mainline valves was found to have no effect on improving safety even if the valve was closed at the time of a line break A variety of remote monitoring systems have been evaluated and some are promising to become commercial services.

- **On-bottom Stability of Off-shore Pipelines**
  The latest version of the definitive design reference manual for assuring the stability of pipelines laid in the subsea environment is presented in a user-friendly, state-of-the-art software that addresses all design considerations, including: coatings; soil characteristics; and pipe-to-soil interactions.

- **Transportation Crossings**
  PC-Pisces, an engineering analysis program, predicts the safe maximum vehicle loading when traversing buried pipelines. PC-Pisces has been used to minimize the problem of casing shorts and the associated accelerated corrosion by establishing safe installation of uncased crossings. PC-Pisces has been adopted in 1993 by the American Railway Engineering Association and by the American Petroleum Institute. This methodology is being updated.

<u>Inspection</u>

- **Hydrostatic Testing to Eliminate Flaws & Defects on In-service Pipelines**
  Based on numerous failure analyses, laboratory studies, field evaluations, and statistical analyses, the primary resource has been developed on the test parameters, benefits, and risks of hydrostatic testing of in-service pipelines in addressing flaws, defects, and damage.

- **Pipeline Simulation Facility**
  The Pipeline Simulation Facility (PSF) was designed to help gas pipeline companies maintain the integrity of their systems, prevent shutdowns, and reduce overall maintenance costs. The Facility was conceived in 1986 and dedicated nearly a decade later in 1995, the current facility can perform full scale, pipeline experiments. Several realistic tests have been performed in the facility since its construction.

  These include:

  – testing of Magnetic Flux Leakage (MFL) corrosion pigs,
  – testing of speed control devises,
  – testing inertial mapping systems,
  – development and testing of SCC detection pigs,
  – development of mechanical damage pigs,
  – testing and development of coating disbondment detection devices,
  – and testing of real time monitoring systems.

- **Purging**
  Addressing the need for safer pipeline purging practices, in 1997 this research resolved industry concerns on specific technical issues of minimum purge velocity, time to complete a purge, and the required nitrogen volume.

Stress Corrosion Cracking (SCC)

- **SCC Characterization**
  A comprehensive model has been created that enables the description of SCC growth from shallow micro cracks to failure of macro cracks, based on crack behavior, pipe properties, and loading history.

- **SCC Initiation Site Prediction**
  A comprehensive model has been developed which relates actual excavated pipe surface inspections with pipe stress, metallurgy and electrochemistry all which must be present simultaneously to cause of SCC. These three require the integration then correlation of various secondary relationships such as pipe metallurgy, design, construction and maintenance history, terrain shape, soil classification, and soil moisture electrochemistry, to predict the absence or presence of SCC initiation sites.

- **SCC Life Prediction Model**
  A software model has been created that assesses the effects of operating conditions (e.g., temperature, peak pressure, and pressure cycles) on crack growth enabling a determination of key risk elements, including: time to failure; failure pressure; and size of flaws at failure.

Welding

- **Pipeline Repair by Direct Weld Deposition**
  In 1999 the Department of Transportation accepted this work, providing the criteria for the use of a safe, efficient alternative to other repair methods and for the remediation of pipe and fittings, including a sound basis for a decision to continue the service of corrosion-pitted pipe when repaired by this approach.

- **Reliability-based Fitness for Service**
  Utilizing the proven "engineering critical assessment (ECA)" approach, this work enables a sound determination of the uncertainties in weld reliability, in both individual and multiple welds on long pipelines, and it provides the criteria and procedures for resolving those uncertainties.

- **Weld Procedures**
  In 1999 through collaborative efforts, the pipeline industry developed safe welding procedures and technologies for new materials such as X80, for underwater welding, and for welded repairs. Special weld pass sequencing procedures were developed that allowed the successive passes to temper previous welds and avoid potential toe cracking leaks in older steel pipe. The welding technology was expanded to include safer hot tapping procedures and even direct deposit welding to restore pipe wall thickness in awkward locations such as elbows.

Key Pipeline Technologies Under Development

The following work currently under development builds on prior work, either as the planned extension of that work, or as the next iteration of that work based on evolving technology and need.

- **Determining the remaining strength of corroded pipe**
  This work will develop the criteria and guidance for application of several remaining-strength models (including RSTRENG and PAFFC) best suited to the nature and type of the affected steel and its operating parameters, thus informing and improving repair and remediation decisions.

- **Software Model for Design of Cathodic Protection (CP)**
  This model will enable CP system designers to develop customized CP programs based on a predictive assessment of such concerns as coating effectiveness, attenuation of current along the pipeline, interference effects from other pipelines and influences (e.g., stray AC), and current distribution near holidays and anodes.

- **Effects of Non-typical Loading Conditions on Buried Pipelines**
  This analysis will provide a design tool for evaluating the impacts on both shallow-buried and normal depth pipelines from large and unusual loads that present concerns resulting from the increasing encroachment of load-inducing activities on pipelines.

- **Monitoring CP Levels in Remote & Inaccessible Locations**
  This work will provide an evaluation tool using scenario protocols to enable pipeline operators to determine if adequate CP is being provided to pipe in locations where traditional CP monitoring is not feasible or safe, and to enable the operator to respond accordingly.

- **Risk Management & Data Integration**
  Industry-wide risk assessment and management technologies have been developed, including a common lexicon that permits optimum application of risk analysis and management principles to pipeline situations.

- **Automatic Encroachment Detection on the Right of Way**
  Radar satellites detect and track heavy equipment entering operating and leaving the right of way. Additional visual satellite images are used to verify the operator. Software is being developed to automatically detect within corridors, confirm, and warn operators of potential 3rd Party Damage.

As pipelines move from paper to electronic records, Integrated Spatial Analyses Techniques (ISAT) is the original dictionary of the pipeline components and risk related data visualized as the center line of the pipe and everything attached to the pipe. PipeView was the original geographical information system (GIS) example to show how to use ISAT to provide electronic alignment sheets. As the process of pipeline Risk Management matured, identification of the root causes that lead to poor performance of pipe, fittings, and other equipment was needed; and Incident Reporting and Tracking System (IRATS) was developed to collect root cause components and sort these to improve safety performance. The GIS Mapping initiative of DOT summarized and the pipeline industry's constructive suggestions. ISAT has evolved into PODS (Pipeline Open Data Standard). PODS is a design tool to help pipelines with the next GIS or integrity management systems to converge integrity inspections embodied as disjointed software applications across company divisions and minimize migration expense of integrating capital equipment, construction, maintenance, and inspection history, and other departmental records as they are updated.

Future Integrity Needs & Opportunities

The pipeline industry's planning and program model directs technology development over a 3-4 year horizon, and it largely builds incrementally on work previously conducted. Eventually these successful projects require outside partners with additional resources to ensure they become a commercial service or product, or are embodied in public codes and standards. Consequently, it is likely that the pipeline's technology agenda will continue to have a strong focus on bringing evolving technologies to bear on known problems that further enhance sound safety margins. It is the pipeline industry's view that the following technology needs and opportunities will need to be addressed.

Mechanical Damage: Several industry sponsored R&D tools are in the expensive commercialization stage. Real Time Monitoring needs to shrink from the microwave oven size to a cell phone size and not require hard wire connections. Satellite radar surveillance and visible light satellite perpetrator verification is commercially available for near real time monitoring and alarm. Both require software enhancements to more effectively eliminate false calls.

Integration of Data: The industry has developed a design tool PODS which has been used in GIS applications capable of generating pipeline alignment sheets showing the capital inventory on maps. Additional tools are required to allow interoperability across marginally related departments with the aim of increased integrity and reliability. These cross functional system design applications have the possibility of reducing the time to meet regulatory requirements for new construction.

Leak Detection: The industry has helped develop research tools to the near commercial stage. Passive and active infrared (IR) laser technology has been shown to work to about 50 feet but great strides in sensitivity are needed before these tools can be mounted on aircraft for leak patrols. Commercial truck mounted IR absorption equipment quickly scans the methane background levels on neighborhood roads for the presence of leaks but patient foot patrols are still required to zero in on these small sources.

Assessment of the Remaining Strength of Corroded Pipelines

Determining the strength of corroded pipes, is an issue the pipeline industry has been working on for a number of years. This work is reviewing the existing databases of metal loss defects from North America and Europe and comparing them to the results of all known assessment methods. The results of this work will be documented in a comprehensive report that recommends particular assessment methodology for different assessment situations.

- **New Materials.**
  Using composite materials and the appropriate procedures to effect pipeline repairs, ie the ClockSpring™ repaired area is restored to it's original performance . Considering its leak-before-burst characteristics, , composite pipe promises to be even safer that all steel pipe currently available to the industry for class upgrades and new construction. Higher strength steels and automatic welding and inspection processes reduce constructions costs.

- **External Corrosion**
  Improved Direct Assessment methods are needed to provide non intrusive, "off-the-pipe," accurate assurance that sufficient CP protection is being applied to buried pipelines in any operating environment.

- **In-Line Inspection (Pigs)**
  Technologies to facilitate the commercial inspection of major pipeline systems using devices known in the industry as "smart pigs" that run inside the pipe itself and can locate and quantify most significant corrosion defects that could cause a pipeline failure. Work is continuing on technologies to detect and quantify certain other defects such as SCC and for which no practical (only prototype) detection and quantification currently exists. These include defects like Mechanical Damage, Stress Corrosion Cracking (SCC), Coating Disbondment, Weld Defects, and Pipeline Material Properties.

- **In-Line Inspection**
  The industry still doesn't have a reliable tool to detect crack like defects in natural gas pipelines, even after more than fifteen years and tens of millions in industry R&D funds. The PII elastic wave tool may expect a 20% success, one in every five calls, gas coupled ultrasonics have several serious physics problems to overcome, liquid coupled ultrasonics are a large operations difficulty, and the non-contact EMAT tools show promise in the lab. Circumferential MFL shows promise for wide long seam corrosion defects but it is still unreliable for tight axial cracks. Normal MFL tools can not detect axial cracks.

  There are no in-line inspection (ILI) tools that can detect mechanical damage. Mechanical damage such as a gouge in a dent may be inferred if two occurrences can be shown to directly coincide. Both a caliper pig must detect a dent and then an MFL tool must not have lift off cause by the dent so it can indicate marginal wall loss at the same location. The industry R&D has shown that lowering the magnetic flux from full wall saturation to partial saturation can detect the change in permeability due to mechanical work. Pipeline ILI tools need to be built and demonstrated at costs of tens of millions.

- **Stress Corrosion Cracking**
  An integrated model is needed for determining/predicting the presence of SCC and characterizing the phenomenon by type (high pH or near-neutral) and identifying the appropriate control response (e.g., replace or repair). Direct Assessment tools need to be developed to reliability locate pipe that have initiated SCC.

- **System Monitoring**
  A system is needed to provide real-time detection, transmission (field to central location), and assessment capability that covers all or a portion (e.g., in high consequence areas) of an operating pipeline to detect the unintentional striking of the pipeline.

APPENDIX C

RELEVANT R&D DELINEATED BY CAUSES/THREATS AND PROCESSES

The following list of references represent pipeline industry research efforts relevant to understanding and preventing pipeline failures. The projects represented by these reports often had scopes much broader than understanding or preventing pipeline failures, but there is no question that these efforts have enhanced pipeline safety and have led directly or indirectly to the relatively low fatality and injury rates per ton-mile of commodity shipped compared to other forms of transportation. The references are categorized by cause of incident to which they are most relevant or to the significant processes such as Risk Management/ Integrity Management. It will be obvious that some references are relevant to more than one cause. Readers who wish to learn more about the contents of particular references will find abstracts for the PRCI documents on the PRCI's web page at www.prci.com. and GRI@www.gastechnology.org.

DEFECTIVE FABRICATION WELD (DFW)

"Advanced Pipe Initiative for Inherently Safer Pipe: A Preliminary Assessment", GRI-99/0098

Kiefner, J.F., Bruce, W.A., and Stephens, D.R., "Pipeline In-Service Repair Manual", Catalog No. L51716, PR-218-9307 (December 1994).

Yi-Wang, et al, EWI and Rosenfeld, M.J., et al, Kiefner and Associates, Inc. "Plastic Deformation Capacity of Girth Welded and Structural Sleeve Connections", Catalog No. L51757, PR-185-9211 (December 1997).

Yi-Want, Y., et al, "Plastic Deformation Capacity of Girth-Welded and Structural Sleeve Connections", Catalog No. L51708, PR-185-9211 (April 1994).

Bruce, W.A. and Kenzie, B.W., "Development of NDI Methods for Welds on In-Service Pipelines III", Catalog No. L51668, PR-185-933.

Bruce, W.A., "Development of Optimized NDI Methods for Hot Tap Branch Welds", Catalog No. L51786, PR-185-9614, (June 1995).

Edison Welding Institute, "Criteria for Hot-Tap Welding, Further Studies", Catalog No. L51602, PR-185-815 (May 1989).

Laverty, K. and Kirk, M., "Development of Fitness-for-Purpose Assessment Procedures for Branch Welds", Catalog No. L51714, PR-185-9332 (July 1994).

Laverty, K. and Kirk, M., "Development of Modeling Procedures for Branch Welds", Catalog No. L51737, PR-185-9430 (November 1995).

Cola, M.J., Bruce, W.A., Kiefner, J.F., Fischer, R.D., Bubenik, T.A., and Jones, D.J., "Development of Simplified Weld Cooling Rate Models for In-Service Gas Pipelines", Catalog No. L51660, PR-185-914 (March 1991; Update & Reprint December 1999).

Bruce, W.A. and Threadgill, P.L., "Effective Procedure Variables for Weld Onto In-Service Pipelines", Catalog No. L51713, PR-185-9329 (July 1994).

Graville, B.A., "Factors Affecting Heat Affected Zone Root Strains in Pipeline Girth Welds and Repairs", Catalog No. L51707, PR-225-9325 (November 1993).

Svedeman, S., "Fitness-for-Purpose Assessment Procedures for Sleeve Welds in Pipelines: Summary Report", Catalog No. L51732, PR-185-014 (December 1994).

Bruce, W.A., "Guidelines for Weld Deposition Repair on Pipelines", Catalog No. L51782, PR-185-9734 (February 1998).

Yi-Wang, Y., Mohr., W., and Sun, X., "Plastic Collapse Solutions for GW Pipes and Sleeves", Catalog No. L51761, PR-185-9431 (May 1997).

Bruce, W.A., "Repair of Pipelines by Direct Deposition of Weld Metal", Catalog No. L51681, PR-185-9110 (June 1993).

Bruce, W.A., Holdren, R.L., and Kiefner, J.F., "Repair of Pipelines by Direct Deposition of Weld Metal--Further Studies", A.G.A. Catalog No. L51763, PR-185-9515 (November 1996).

McGaugy, T., "Repair Weld Residual Stress", A.G.A. Catalog No. L51678, PR-185-9104 (March 1993).

Threadgill, P.L. and Cola, M.J., "Review of Procedures for Welding onto Pressurized Pipelines", A.G.A. Catalog No. L51601, PR-18-815 (May 1989).

Watson, P.D., "State-of-the-Art Review of Underwater Wet Welding", A.G.A. Catalog No. L51727, PR-15-9433 (February 1995).

Goldak, J., "Welding on Fluid Filled Pressurized Pipelines: Transient 3D Analysis of Temperature, Microstructure, Stress, and Strain", A.G.A. Catalog No. L51647, PR-206-013 (March 2000).

"Effect of Procedure qualification Variables for Welding Onto In-Service Pipelines", GRI-94/0482 AGA-PR-185-9329

DEFECTIVE PIPE GIRTH WELD (DGW)

Feole Technologies, Inc., "Automation of FAST Ultrasonic Technique for Weld", Catalog No. L51777. PR-250-9612 (June 1995).

Tucker, J.E., et al, "Evaluation of the Feasibility of a Pipeline Field Weld Real-time Radiography (Radioscopy) Inspection System", Catalog No. L51728, PR-231-9419.

Van der Ent, J. and Dijkstra, F.H., "Evaluation of Ultrasonic Inspection Techniques for the Root Region of Girth Welds", Catalog No. L51734, PR-220-9123 (January 1996).

Dijkstra, F.H. and Blinde, M.R., "Evaluation of Ultrasonic Technology for Volumetric Weld Inspection of Pipeline Girth Welds", Catalog No. L51776, PR-220-9437 (December 1997).

Denys, R.M. and Lefevre, T., "Alternative Acceptance Criteria of Girth Weld Defects", Catalog No. L51771, PR-202-9328 (June 1997).

Denys, R.M., "Effect of Weld Metal Matching on Girth Weld Performance Vol. I", Catalog No. L51651, PR-202-922 (February 1992).

Denys, R.M., "Effect of Weld Metal Matching on Girth Weld Performance, Volume II: Experimental Investigation", Catalog No. L51685, PR-202-922 (January 1993).

Denys, R.M. and Martin, T., "Effect of Weld Metal Matching on Girth Weld Performance, Volume III: An Engineering Critical Assessment (ECA) Analysis", Catalog No. L51711, PR-202-922 (June 1994).

Howse, D.S. and Jones, R.L., "Evaluation of Low Hydrogen Welding Processes for Pipeline Construction in High Strength Steel", Catalog No. L51751, PR-164-9330 (August 1996).

Graville, B.A., "Factors Affecting Heat Affected Zone Root Strains in Pipeline Girth Welds and Repairs", Catalog No. L51707, Pr-225-9325 (November 1993).

Denys, R.M., "Fracture Behavior of Girth Welds Containing Natural Defects, Comparison with Existing Workmanship Standards", Catalog No. L51653, PR-202-009 (February 1992).

Denys, R.M., "Fracture Behavior of Large Diameter Pipeline Girth Welds: Effect of Weld Metal Yield Strength - Part 1", Catalog No. L51652, PR-202-011 (February 1992).

Denys, R.M., "Fracture Behavior of Large-Diameter Pipeline Girth Welds: Effect of Weld Metal Yield Strength and Defect Interaction, Part II", Catalog No. L51712, PR-202-011 (May 1994).

Patchett, B.M. and Bicknell, A.C., "Higher-Strength SMAW Filler Metals", Catalog No. L51706, PR-152-012 (December 1993).

Graville, B.A., "Hydrogen Cracking in the Heat Affected Zone of High Strength Steels--Year 2, Development of Weld Metal Test", Catalog No. L51764, PR-225-9516 (May 1997).

Orth, F.J., "Investigation of Fatigue Properties of Girth Welds with Root Imperfections Allowed by API 1104", Catalog No. L51762, PR-185-9432 (January 1997).

Yi-Wang, Y., Mohr, W., and Sun, X., "Plastic Collapse Solutions for GW Pipes and Sleeves", Catalog No. L51761, PR-185-9431 (March 1997).

Warke, R.W. and Ferregut, C., "Reliability-Based Fitness for Service Assessment of Welds", Catalog No. L51779, PR-185-9429 (June 1998).

Weston, J., "Study of Processes for Welding Pipelines", Catalog No. L51649, PR-164-007 (June 1991).

Denys, R.M. and Lefecre, T., "Weld Metal Yield Strength Testing of Girth Welds", Catalog No. L51738, PR-202-9326 (February 1996).

DEFECTIVE PIPE (DP)

VanFoeken, R.J. and Gresnigt, A.M., "Buckling and Collapse of UOE Manufactured Steel Pipes", A.G.A. Catalog No. L51809, PR-238-9423, 132 pages (November 1998).

Gray, J.M., Frazackerley, R.L., and Fazackerley, W.J., "Tensile Property Variation in DSAW and ERW Line Pipe", A.G.A. Catalog No. L51805, PR-187-9602, 230 pages (July 1996).

Gray, J.M., Chen, C.C., Subramamian, S.V., Peters, P.A., and Abbott, T., "Centerline Segregation in Plate and Strip for Linepipe Produced from Continuously Cast Slabs", A.G.A. Catalog No. L51759, PR-187-9212, 91 pages (July 1996).

Maxey, W.A. and Barnes, C.R., "Chevron Notch for DWTT Use on High-Toughness Steel", A.G.A. Catalog No. L51622, Report 190, 91 pages (September 1990).

Leis, B.N., Brust, F.W., and Scott, P.M., "Development and Validation Ductile Flaw Growth Analysis", A.G.A. Catalog No. L51643, Report 193, 140 pages (June 1991).

Leis, B. N., "Ductile Fracture & Mechical Behavior of X42 and X80 Pipe Steels", A.G.A. Catalog No. L51683, Report 204, 56 pages (October 1992).

Groeneveld, T.P., "Evaluation of Modern X70 and X80 Line Pipe Steels", A.G.A. Catalog No. L51676, Report 201, 101 pages (April 1992).

Groeneveld, T.P., "Evaluation of Modern X-70 HFER Line Pipe", A.G.A. Catalog No. L51690, Report 203, 40 pages (May 1992).

Olson, R.J., "Evaluation of the Structural Integrity of Cold Field-Bent Pipe", A.G.A. Catalog No. L51740, PR-3-9214, 40 pages (May 1996).

Leis, B.N. and Brust, F.W., "Hydrotest Strategies for Gas Transmission Pipelines - Ductile Flaw", A.G.A. Catalog No. L51665, Report 194, 57 pages (July 1992).

Leis, B.N., Walsh, W., and Brust, F.W., "Mechanical Behavior of Selected Line Pipe Steels", A.G.A. Catalog No. L51624, Report 192, 31 pages (September 1990).

Leis, B.N. and Ghadiali, N.D., "Pipe Axial Flaw Failure Criteria -- PAFFC, Version 1.0 User's Manual and Software", A.G.A. Catalog No. L51720, Report 211, 47 pages (May 1994).

Maxey, W.A. and Eiber, R. J., "Yield Tensile Ratio Effect on Line Pipe Behavior", A.G.A. Catalog No. L51562, Report 168, 55 pages (August 1988).

Fowler, J.R., Mahmod, M.S., and Al-Sannaa, M.S., "High Pressure Pipe Design", A.G.A. Catalog No. L51703, PR-201-9202, 90 pages (January 1993).

Zimmerman, T.J.E.,, Chen, Q., and Pandey, M.D., "Limit States and Reliability-Based Pipeline Design", A.G.A. Catalog No. L51769, PR-244-9517, 104 pages (June 1997).

Denys, R.M., "Effect of Defect Size and Yield to Tensile Ratio on Plastic Deformation Capacity Pipeline Steels", A.G.A. Catalog No. L51686, PR-202-010, 86 pages (January 1993).

Dennys, R.M. and Lefecre, T., "Effect of Defect Size and YS/TS Ratio on the Plastic Deformation Capacity of X70 and X80 Pipe Steels", A.G.A. Catalog No. L51739, PR-202-9327, 137 pages (February 1996).

Denys, R.M. and Lefecre, T., "Interaction of Multiple Through-Thickness Defects", A.G.A. Catalog No. L51780, PR-202-9514, 99 pages (1998).

Francini, R. B., Burgoon, D. A., Chang, O. C., Leis, B. N., Rust, S. W., and Clark, E. B., "An Alternative to 49 CFR192 Appendix B to Determine Unknown Yield Strength of Pipelines", A paper presented at the *ASME Energy Technology Conference and Exhibit*, 21 pages (January 2000).

Bilston, P. and Murray, N., "The Role of Cold Field Bending in Pipeline Construction", *Eighth Symposium on Line Pipe Research*, Pipeline Research Committee, American Gas Association, Catalog No. L51680, 19 pages (1993).

Olson, R., Clark, T., and Odom, T., "Evaluation of the Structural Integrity of Cold Field-Bent Line Pipe", *Ninth Symposium on Pipeline Research*, PRC*I*, 20 pages (1996).

Kiefner, J. F., and Morris, W. G., "Considerations for Line Pipe Material Reliability", OTC 8498, Paper for *1997 Offshore Technology Conference*, pp 55-60, Houston, Texas (May 1997).

Kiefner, J. F., and Clark, E. B., *History of Line Pipe Manufacturing in North America*, ASME Research Report CRTD-Vol. 43, Book Number 100396, 292 pages (1996).

"History of Line pipe Manufacturing in North America", GRI-96/0487 ASME-CRTD-VOL.43

DEFECTIVE PIPE SEAM (DPS)

Buehler, W.M., McHaney, J.H., and Bruno, T.V., "Evaluation of Laser Welded Line Pipe", A.G.A. Catalog No. L51812, PR-253-9703 (July 1999).

Groeneveld, T.P., "Evaluation of Modern X-70 HFER Line Pipe", A.G.A. Catalog No. L51690, Report 203, 40 pages (May 1992).

Leis, B.N. and Brust, F.W., "Hydrotest Strategies for Gas Transmission Pipelines - Ductile Flaw", A.G.A. Catalog No. L51665, Report 194, 57 pages (July 1992).

Cialone, H.J. and Williams, D.N., "Investigation of Sulfide-Stress Cracking at Pipe Seam Welds", A.G.A. Catalog No. L51589, Report 184, 53 pages (August 1989).

Groeneveld, T.P., et al, "Seam-Weld Quality of Modern ERW/HFI Pipe", A.G.A. Catalog No. L51663, Report 198, 28 pages (September 1991).

Lukezich, S.J, "Susceptibility of Modern ERW Pipe to Corrosion in Wet", A.G.A. Catalog L51775, PR-15-9306, 77 pages (February 1998).

Feole, R.A., "Automation of FAST Ultrasonic Technique for Weld", A.G.A. Catalog No. L51777, RP-250-9612, 25 pages (June 5).

Kiefner, J. F., and Morris, W. G., "Considerations for Line Pipe Material Reliability", OTC 8498, Paper for *1997 Offshore Technology Conference*, pp 55-60, Houston, Texas (May 1997).

Kiefner, J. F., and Clark, E. B., *History of Line Pipe Manufacturing in North America*, ASME Research Report CRTD-Vol. 43, Book Number 100396, 292 pages (1996).

Grimes, K., "A Breakthrough in the Detection of Long Seam Weld Defects in Steel Pipelines", Pipeline Integrity International (1999).

Maxey, W. A., Mesloh, R. E., and Kiefner, J. F., "Use of the Elastic Wave Tool to Locate Cracks Along the DSAW Seam Welds in a 32-Inch (812.8 mm) OD Products Pipeline", *International Pipeline Conference*, Volume 1, ASME (1998).

Miller, S. E., Gardiner, M. A., and Ward, C. R., "In-Line Inspection Detects Early Cracking on Canadian Crude-Oil Line", *Oil and Gas Journal*, 5 pages (September 28, 1998).

Willems, H. H., and Barbian, O. A., "Crack Detection in Pipelines: Survey Experience Obtained with the Ultrascan CD Tool", *The Pipeline Pigging Conference*, 9 pages (February 14-16, 1996).

Willems, H. H., Barbian, O. A., and Uzelac, N. I., "In-Line Inspection Tools for Crack Detection in Gas and Liquid Pipelines", *International Pipeline Conference*, Volume 1, ASME, 8 pages (1998).

Ward, C. R., and Mann, A. S., "Field Evaluation of British Gas Elastic Wave Inspection System for SCC Detection", *Eighth Symposium on Line Pipe Research*, A.G.A. Pipeline Research Committee, Catalog No. L51680, 13 pages (1993).

EXTERNAL CORROSION (EC)

"Guide for the Monitoring and Treatment of Microbiologically Influenced Corrosion in the Natural Gas Industry: 1998", GRI-96/0488

"Technology Assessment of External Microbiologically Influenced corrosion (MIC)" GRI-98/0386

"Summary of Validation of ClockSpring™ for Permanent Repair of Pipeline Corrosion Defects", GRI-98/0227

Gummow, R.A., “Cathodic Protection Considerations for Pipelines w/ AC Mitigation Facilities”, A.G.A. Catalog No. L51800, PR-262-9809, 89 pages (January 1999).

Perdomo, J.J., and Payer, J.H., “Chemical and Electrochemical Conditions on Steel at Disbonded Coatings”, A.G.A. Catalog No. L51736, PR-75-9310, 181 pages (June 1995).

Thompson, N.G., Beavers, J.A., and Han, M.K., “Criteria to Stop Active Pit Growth”, A.G.A. Catalog No. L51544, PR-3-165, 60 pages (January 1987).

Technical Inspections Services, Inc., “Effects of Phosphoric Acid Treatment on Performance of FBE Coating”, A.G.A. Catalog No. L51798, PR-247-9511, 211 pages (October 1998).

Thompson, N.G. and Lawson, K.M., “External Corrosion Control Monitoring Practices (Vol. I & II)”, A.G.A. Catalog No. L51792, PR-186-9610, 222 pages (May 1998).

Thompson, N.G. and Lawson, K.M., "Impact of Short-Term Depolarization of Pipelines", A.G.A. Catalogy No. L51801, PR-186-9611, 74 pages (February 1999).

Kiefner, J.F., Vieth, P., Orban, J., and Feder, P., "Methods Prioritizing Pipe Maintenance and Rehabilitation", A.G.A. Catalog No. L51631, PR-3-919, 186 pages (September 1990).

Kiefner, J.F. and Vieth, P., "Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe (RSTRENG) (Includes: L51688, RSTRENG2 User's Manual and Software)", A.G.A. Catalog No. L51688B, PR-3-805, 80 pages (December 1989).

Macdonald, D.D., Balachov, I., Sikora, J., Kirksunov, I., and Urquidi-Macdonald, M., "New Technique to Assess Level of Cathodic Protection in Underground Pipe Systems", A.G.A. Catalog No. L51750, PR-12-9314, 133 pages (February 1996).

Vol I&II: Dawalibi, F, Southey, R., Malric, Y., Tavcar, W., Vol III: Dabkowski, J., Frazier, M., "Power Line Fault Current Coupling to Nearby Natural Gas Pipelines (3-Vols)", A.G.A. Catalog No. L51537, PR-151-634, 315 pages (November 1988).

Nunez, S., Coulson, K., Choate, L.C. and Banach, J.L., "Review of Gas Industry Pipeline Coating Practices", A.G.A. Catalog No. L51586, 18 pages (July 1988).

Barlo, T. and Werner, D., "Shielding Effects of Concrete and Foam External Pipeline Coatings", A.G.A. Catalog No. L51656, PR-208-631, 63 pages (January 1992).

Leis, B.N., Forte, T.P., and Ghadiali, N.D., "Stress Corrosion Cracking Life Prediction Model (SCCLPM) Version 1.0 User's Manual and Software", A.G.A. Catalogy No. L51808, Report 217, 37 pages (November 1995).

Orazem, M.E. and Carson, S.L., "Time-Dependent Polarization Behavior as a Function of Soil Type", A.G.A. Catalog No. L51735, PR-101-9221, 361 pages (June 1995).

Kiefner, J.F. and et al, "Continued Validation of RSTRENG", A.G.A. Catalog No. L51749, PR-218-9304, 150 pages (December 1996).

Stephens, D.R., et al, "Development of Alternative Failure Criterion for Res. Strength-PCORRC", A.G.A. Catalog No. L51794, PR-3-9509, 83 pages (January 1999).

"Stephens, D.R., et al, "Residual Strength of Pipeline Corrosion Defects Under Combined Pressure and Axial Loads", A.G.A. Catalog No. L51722, Report 216, 100 pages (February 1995).

Rosenfeld, M.J., "Serviceability of Corroded Girth Welds", A.G.A. Catalog No. L51742, PR-218-9434, 77 pages (May 1996).

Lukezich, S.J., "Susceptibility of Modern ERW Pipe to Corrosion in Wet", A.G.A. Catalog No. L51775, PR-15-9306, 77 pages (February 1998).

Crouch, A.E., "Assessment of NDT Needs for Pipeline Integrity Assurance II", A.G.A. Catalog No. L51747, PR-15-9507, 76 pages (June 1995).

Lank, A. and Mudge, P., "Development of Long Range Ultrasonic Methods of Assessing Pipeline Condition (Phase 4)", A.G.A. Catalog No. L51785, PR-164-9207, 58 pages (June 1995).

Nestleroth, J.B., "Evaluation of Circumferential Magnetic Flux for In-Line Detection of Stress Corrosion Cracks and Selective Seam Weld Corrosion", A.G.A. Catalong No. L51811, PR-3-9420, 38 pages (September 1999)

Fowler, J.R. and Curington, D., "Determination of Clamp Repairable Leaks", Catalog No. L51701, PR-201-9114, 25 pages (January 1993).

Stress Engineering Services, "Development of a Diverless Pipeline Repair Clamp, Phase II", A.G.A. Catalog No. L51669, PR-201-019, 154 pages (April 1992).

H.O. Mohr Research & Engineering, "Diver Assisted Repair Manual", A.G.A. Catalog No. L51679, PR-209-9122, 256 pages (December 1992).

Stress Engineering Services, Inc., "Diverless Pipeline Repair Clamp I", A.G.A. Catalog No. L51659, PR-201-019, 95 pages (August 1993).

Miller, J. E., "Diverless Pipeline Repair Clamp, Phase III", A.G.A. Catalog No. L51699, PR-201-019, 100 pages (August 1993).

J.P. Kenny Offshore Engineering, Inc., "Guidelines for Riser Splash Zone Design and Repair", A.G.A. Catalog No. L51726, PR-189-9322, 112 pages (February 1995).

Nessim, M.A. and Pandey, M.D., "Reliability Based Planning of Inspection & Maintenance", A.G.A. L51765, PR-224-9519, 93 pages (January 1997).

Muhlbauer, W. Kent, *Pipeline Risk Management Manual*, Gulf Publishing Company (1992). Second Edition (1996). Also *Pipeline Risk Controller*, Version 2.0 for Windows®

Kulkarni, R.B. and Conroy, J.E., "Pipeline Inspection and Maintenance Optimization System (PIMOS)", *Pipeline Risk Assessment, Rehabilitation and Repair Conference* (September 12-15, 1994).

Kirkwood, M.G. and Karam, M., "A Scheme for Setting Pipeline Repair, Maintenance and Inspection Priorities", *Pipeline Risk Assessment, Rehabilitation and Repair Conference* (September 12-15, 1994).

Stephens, M.J. and Nessim, M.A., "Pipeline Maintenance Planning Based on Quantitative Risk Analysis", *International Pipeline Conference - Volume 1*, ASME (1996).

Kiefner, J.F., Morris, W.G., Vieth, P.H., and Wiegele, E.J., "A Risk Management Tool for Establishing Budget Priorities", *6th International Conference & Exhibition on GIS for the Oil & Gas Industry* (September 8-10, 1997).

Beighle, B. D. and Gloven, M. P., "Relative Risk - "The Competitive Advantage"", *International Pipeline Conference - Volume I*, ASME (1998).

Acton, M. R., Baldwin, P. J., Baldwin, T. R., and Jager, N. V., "The Development of the PIPESAFE Risk Assessment Package for Gas Transmission Pipelines", *International Pipeline Conference - Volume I*, ASME (1998).

Vieth, P.H., Rust, S.W., Johnson, E.R., and Cox, M.L., "Corrosion Pig Performance Evaluation", National Association of Corrosion Engineers (NACE), *NACE/96*, Denver, Colorado (March 1996).

Rust, S.W., Vieth, P.H., Johnson, E.R., and Cox, M.L., "Quantitative Corrosion Risk Assessment Based on Pig Data", National Association of Corrosion Engineers (NACE), *NACE/96*, Denver, Colorado (March 1966).

Vieth, P.H., Ashworth, B.P., and Sahney, Reena, "TCPL In-Line Inspection Management Program", *Proceedings of the International Pipeline Conference 1998*, Offshore Mechanics and Arctic Engineering Division, American Society of Mechanical Engineers (ASME), Calgary, Alberta, Canada (June 7-11, 1998).

Anon., "Risk Management Program Standard" (for use in the Pipeline Risk Management Demonstration Program), Produced by the Joint Risk Management Standard Team, The Office of Pipeline Safety, American Petroleum Institute, Interstate Natural Gas Association of America, National Association of Pipeline Safety Representatives, Gas Research Institute (1996).

Stirling, D. G., "Evaluation of Coating Condition Using the Elastic Wave Pig", Final Report, GRI 97/0073, 29 pages (1997).

Crouch, A. E., Bruton, F. A., and Bartlett, G. R., "In-Line Inspection of Unpiggable Natural Gas Pipelines", Topical Report, GRI 95/0323, 86 pages (October 1995).

Nestleroth, J. B., Rust, S. W., Burgoon, D. A., and Haines, H., "Determining Corrosion Defect Geometry From Magnetic Flux Leakage Pig Data", *The NACE International Annual Conference and Exposition 96*, Paper No. 44 (1996).

Vieth, P. H., Rust, S. W. and Ashworth, B. P., "Use of In-line Inspection Data for Integrity Management", Paper No. 547, *Corrosion 99*, 9 pages (1999).

Crouch, A. E., "In-Line Inspection of Natural Gas Pipelines", Topical Report, GRI 91-0365 (May 1993).

Goedecke, H., "Corrosion Surveys with the UltraScan Pig", *Pipe Line Industry* and *Pipes and Pipelines International* (1990).

Maltby, P. M. and Hamilton, J. C., "An Ultrasonic Pipeline Inspection System", *Pipeline Pigging and Inspection Technology Conference*, 21 pages (February 1991).

"Advanced Magnetic Flux Leakage Signal Analysis for Detection and Sizing of Pipeline Corrosion: Field Evaluation Program", GRI-00/0109

"Detection and Sizing of Pipeline Corrosion in Difficult Access Areas Using EMATS", GRI-00/0029

"Development of Techniques for Monitoring Pipeline Coatings with the Elastic Wave In-Line Inspection Vehicle", GRI-00/0160

"Induced AC Influence on Pipeline Corrosion and Coating Disbondment", GRI-95/0004

"Mechanism of Disbonding of Pipeline Coatings", GRI-95/0459

"Models for Mitigating Corrosion Under Disbonded Coating on Steel Pipeline", GRI-98/0337

"Prediction of the Field Performance of Anti-Corrosion Coatings for Buried Steel Pipelines", International Gas Research Conference, 1992. Conference Paper, April 1993, vl, p512-521

"State-of-the-Art for the Use of Anti-Corrosion Coatings on Buried pipelines in the Natural Gas Industry", GRI-92/0004

EARTH MOVEMENT (EM)

Kiefner, J.F., Olsen, R.J., and Gideon, D.N., "Non-Conventional Means for Monitoring Pipelines in Areas of Soil Subsidence or Soil Movement", A.G.A. Catalog No. L51574, Report 166, 59 pages (June 1988).

Rosenfeld, M.J., "Pipeline In-Service Relocation Engineering Manual", A.G.A. Catalog No. L51717, PR-218-9308, 147 pages (December 1994).

Esparaza, E.D., "Pipeline Response to Blasting in Rock", A.G.A. Catalog No. L51661, PR-15-712, 63 pages (September 1991).

Esparaza, E.D., Westine, P.S., and Wenzel, A.B., "Pipeline Response to Buried Explosive Detonations", A.G.A. Catalog No. L51406, PR-15-109, 309 pages (August 1981, Reprint and Update December 1999).

Berthold, J.E., "Fiber Optic Strain Monitoring of Pipelines", A.G.A. Catalog No. L51778, PR-255-9616, 65 pages (1998).

O'Rourke, M., Leon, R. L., and Wang, L. R., "Earthquake Response of Buried Pipeline," Paper in *Proc ASCE Geotechnical Engineering Division Specialty Conference*, Earthquake Engineering and Soil Dynamics, Pasadena, California (June 19-21, 1978). Am. Soc. Civ. Eng., pp 720-731 (1978).

Anon., *Guidelines for the Seismic Design of Oil and Gas Pipeline Systems*, Committee on Gas and Liquid Fuel Lifelines of the ASCE Technical Council on Lifeline Earthquake Engineer, D.J. Nyman, Chairman, ASCE, 484 pages (1984).

Honegger, D. G., *Manual for the Seismic Design and Assessment of Natural Gas Transmission Pipelines,* Preliminary Draft (December 1998).

Stewart, H. E., Ingraffea, R. R., O'Rourke, T. D., and Behn, "Design of Uncased Pipelines at Railroad and Highway Crossings," *API Pipeline Conference*, Houston, Texas (April 7-8, 1992).

Peng, S. S., *Surface Subsidence Engineering*, Society for Mining, Metallurgy, and Exploration, Inc., Littleton, Colorado (1992).

Peng, S. S., and Luo, Y., "Users Manual for CISPM - Comprehensive and Integrated Subsidence Prediction Model," West Virginia University, Morgantown, West Virginia (October 1994).

Kiefner, J. F., "Monitoring and Intervention on Pipelines in Mining Subsidence Area," NG-18 Report No. 155 to the American Gas Association, Battelle Memorial Institute, A.G.A. Catalogue L51515 (August 1986).

Kiefner, J. F., Wall, T. T., Ghadiali, N. D., Prabhat, K., and Rodabaugh, E. C., "Guidelines for Lowering Pipelines While in Service," Battelle report to USDOT/OPS, ASME, and API, Report No. DOT-RSPA-DMT-30/84/8, NTIS, Springfield, Virginia (February 25, 1985).

Kiefner, J. F., Tuten, J. M., and Wall, T. A., "Preventing Pipeline Failures in Areas of Soil Movement - Part 1, State of the Art□A Report of 1985 Activities", NG-18 Report No. 156 to the American Gas Association, Battelle Memorial Institute, A.G.A. Catalog No. L51515 (August 8, 1986).

Olson, R. J., and Kiefner, J. F., "Guidelines for Pipeline Strain Monitoring by Conventional Means", NG-18 Report No. 164 to the American Gas Association, Battelle Memorial Institute, A.G.A. Catalog No. L51515 (December 1987).

Anon., "Satellite Radar Interferometry to Detect and Characterize Slope Motion Hazardous to Gas Pipelines: A Demonstration Study of Three Sites", prepared by the Hartford Steam Boiler and Inspection and Insurance Company, GRI 99/0096, 50 pages (1998).

Stephens, D. R., Olson, R. J., and Rosenfeld, M. J., "Pipeline Monitoring - Limit State Criteria," NG-18 Report No. 188 to the American Gas Association, Battelle Memorial Institute, A.G.A. Catalogue L51620 (January 1990).

Watson, P.D., "Installation of Pipelines by Horizontal Directional Drilling - Enginerring Design Guide", A.G.A. Catalog L51730, PR-227-9424, 110 pages (April 1995).

Danish Hydraulic Institute, "Integrity Assessment of Exposed/Unburied Pipe in River", A.G.A. Catalog No. L51767, PR-170-9520, 100 pages (April 1967).

"Pipeline Free Span Design – Volume 1 and 2", A.G.A. Catalog NO. L51768, PR-170-9522.

Brown & Root Energy Services, "Submarine Pipeline On-Bottom Stability Vol 1 and 2", A.G.A. Catalog No. L51790A/B, PR-178-918, 668 pages (December 1998).

Trow Consulting Engineers, "Water Crossing Design and Installation Manual", A.G.A. Catalog No. L51752, PR-237-9428, 365 pages (August 1996).

Hunt, H., "Vibrating Pig for Measuring Free Spans, Depth of Cover", *Pipeline and Gas Journal* (August 1996).

"Effects of Non-Typical Loading Conditions on Buried Pipelines", GRI-98/0391 PR-15-9521

GASKET O-RING FAILURE (GF)

Cooke, L., "100,000 Hour Design Life of Turbo Compressor Packages", A.G.A. Catalog No. L51783, PR-253-9622 (June 1995).

Howard, T., Kantamaneni, R., and Jones, G., "Cost Effective Leak Mitigation at Natural Gas Transmission Compressor Stations", A.G.A. Catalog No. L51802, PR-246-9526 (August 1999).

HEAVY RAINS/FLOODS (HRF)

Watson, P.D., "Installation of Pipelines by Horizontal Directional Drilling - Enginerring Design Guide", A.G.A. Catalog No. L51730,PR-227-9424 (April 1995).

Danish Hydraulic Institute, "Integrity Assessment of Exposed/Unburied Pipe in River", A.G.A. Catalog No. L51767, PR-170-9520 (April 1967).

"Pipeline Free Span Design – Volume 1 and 2", Catalog No. L51768, PR-170-9522.

Brown & Root Energy Services, "Submarine Pipeline On-Bottom Stability Vol 1 and 2", Catalog No. L51790A/B, PR-178-918 (December 1998).

Trow Consulting Engineers, "Water Crossing Design and Installation Manual", A.G.A. Catalog No. L51752, PR-237-9428 (August 1996).

Hunt, H., A Vibrating Pig for Measuring Free Spans, Depth of Cover□, *Pipeline and Gas Journal* (August 1996).

INTERNAL CORROSION (IC)

"Untrasonics" An Environmentally Benign Mitigation of Microbiologically Influenced Corrosion, Phase 3.1: Long-Term Performance", GRI-98/0085

Lyle, Jr., F.F., "CO2/HS Corrosion Under Wet Low-Flow Gas Pipeline Conditions in Presence of Bicarbonate, Chloride, & Oxygen", A.G.A. Catalog No. L51784, PR-15-9313 (June 1997).

Sridhar, N. and Dunn, D.S., "Effects of Water Chemistry on Internal Corrosion of Steel Pipelines", A.G.A. Catalog No. L51793, PR-15-9712 (July 1998).

Kiefner, J.F., Vieth, P., Orban, J., and Feder, P., "Methods Prioritizing Pipe Maintenance and Rehabilitation", A.G.A. Catalog No.L51631, PR-3-919 (September 1990).

Cialone, H.J. and Williams, D.N., "Investigation of Sulfide-Stress Cracking at Pipe Seam Welds", A.G.A. Catalog No. L51589, Report 184 (August 1989).

Cialone, H.J. and Williams, D.N., "Investigation of Sulfide-Stress Cracking at Pipe Seam Welds", A.G.A. Catalog No. L51589, Report 184 (August 1989).

Crouch, A.E., "Assessment of NDT Needs for Pipeline Integrity Assurance II", A.G.A. Catalog No. L51747, PR-15-9507 (June 1995).

Lank, A. and Mudge, P., "Development of Long Range Ultrasonic Methods of Assessing Pipeline Condition (Phase 4)", A.G.A. Catalog No. L51785, PR-164-9207 (June 1995).

Nestleroth, J.F., "Evaluation of Circumferential Magnetic Flux for In-Line Detection of Stress Corrosion Cracks and Selective Seam Weld Corrosion", A.G.A. Catalog No. L51811, PR-3-9420 (September 1999).

Fowler, J.R., and Curington, D., "Determination of Clamp Repairable Leaks", A.G.A. Catalog No. L51701, PR-201-9114 (January 1993).

Stress Engineering Services, Inc., "Development of a Diverless Pipeline Repair Clamp, Phase II", A.G.A. Catalog No. 51669, PR-201-019 (April 1992).

H.O. Mohr Research & Engineering, "Diver Assisted Repair Manual", A.G.A. Catalog No. L51679, PR-209-9122 (December 1992).

Miller, J.E., "Diverless Pipeline Repair Clamp I", A.G.A. Catalog No. L51659, PR-201-019 (August 1993).

Miller, J.E., "Diverless Pipeline Repair Clamp, Phase III", A.G.A. Catalog No. L51699, PR-201-019 (August 1993).

Nessim, M.A. and Pandey, M.D., "Reliability Based Planning of Inspection & Maintenance", A.G.A. Catalog No. L51765, PR-224-9519 (January 1997).

Yi-Wang, Y. and Bruce, W.A., "Examination of External Weld Deposition Repair for Internal Internal Wall Loss", A.G.A. Catalog No. L51781, PR-185-9633 (March 1998).

Muhlbauer, W. Kent, *Pipeline Risk Management Manual*, Gulf Publishing Company (1992). Second Edition (1996). Also *Pipeline Risk Controller*, Version 2.0 for Windows®

Kulkarni, R.B. and Conroy, J.E., "Pipeline Inspection and Maintenance Optimization System (PIMOS)", *Pipeline Risk Assessment, Rehabilitation and Repair Conference,* (September 12-15, 1994).

Kirkwood, M.G. and Karam, M., "A Scheme for Setting Pipeline Repair, Maintenance and Inspection Priorities", *Pipeline Risk Assessment, Rehabilitation and Repair Conference* (September 12-15, 1994).

Stephens, M.J. and Nessim, M.A., "Pipeline Maintenance Planning Based on Quantitative Risk Analysis", *International Pipeline Conference - Volume 1*, ASME (1996).

Kiefner, J.F., Morris, W.G., Vieth, P.H., and Wiegele, E.J., "A Risk Management Tool for Establishing Budget Priorities", *6th International Conference & Exhibition on GIS for the Oil & Gas Industry* (September 8-10, 1997).

Beighle, B. D. and Gloven, M. P., "Relative Risk - "The Competitive Advantage"", *International Pipeline Conference - Volume I*, ASME (1998).

Acton, M. R., Baldwin, P. J., Baldwin, T. R., and Jager, N. V., "The Development of the PIPESAFE Risk Assessment Package for Gas Transmission Pipelines", *International Pipeline Conference - Volume I*, ASME (1998).

Hartford Steam Boiler Inspection and Insurance Company and Radian Corporation, "Natural Gas Pipeline Risk Management, Volume I - Selected Technical Terminology", Gas Research Institute, GRI-95/0228.1 (October 1995).

Hartford Steam Boiler Inspection and Insurance Company and Radian Corporation, "Natural Gas Pipeline Risk Management, Volume II - Search of Literature Worldwide on Risk Assessment/Risk Management for Loss of Containment", Gas Research Institute, GRI-95/0228.3 (October 1995).

Hartford Steam Boiler Inspection and Insurance Company and Radian Corporation, "Natural Gas Pipeline Risk Management, Volume III - Industry Practices Analysis", Gas Research Institute, GRI-95/0228.3 (October 1995).

Hartford Steam Boiler Inspection and Insurance Company and Radian Corporation, "Natural Gas Pipeline Risk Management, Volume IV - Identification of Risk, GRI-95/0228.4 (October 1995).

Vieth, P.H., Rust, S.W., Johnson, E.R., and Cox, M.L., "Corrosion Pig Performance Evaluation", National Association of Corrosion Engineers (NACE), *NACE/96*, Denver, Colorado (March 1996).

Rust, S.W., Vieth, P.H., Johnson, E.R., and Cox, M.L., "Quantitative Corrosion Risk Assessment Based on Pig Data", National Association of Corrosion Engineers (NACE), *NACE/96*, Denver, Colorado (March 1966).

Vieth, P.H., Ashworth, B.P., and Sahney, Reena, "TCPL in-Line Inspection Management Program", *Proceedings of the International Pipeline Conference 1998*, Offshore Mechanics and

Arctic Engineering Division, American Society of Mechanical Engineers (ASME), Calgary, Alberta, Canada (June 7-11, 1998).

Anon., "Risk Management Program Standard" (for use in the Pipeline Risk Management Demonstration Program), Produced by the Joint Risk Management Standard Team, The Office of Pipeline Safety, American Petroleum Institute, Interstate Natural Gas Association of America, National Association of Pipeline Safety Representatives, Gas Research Institute (1996).

Crouch, A. E., Bruton, F. A., and Bartlett, G. R., "In-Line Inspection of Unpiggable Natural Gas Pipelines", Topical Report, GRI 95/0323, 86 pages (October 1995).

Crouch, A. E., "In-Line Inspection of Natural Gas Pipelines", Topical Report, GRI 91-0365 (May 1993).

Goedecke, H., "Corrosion Surveys with the UltraScan Pig", *Pipe Line Industry* and *Pipes and Pipelines International* (1990).

Maltby, P. M. and Hamilton, J. C., "An Ultrasonic Pipeline Inspection System", *Pipeline Pigging and Inspection Technology Conference*, 21 pages (February 1991).

"Advanced Magnetic Flux Leakage Signal Analysis for Detection and Sizing of Pipeline Corrosion: Field Evaluation Program", GRI-00/0109

"Biocide and Corrosion Inhibition Use in the Oil and Gas Industry: Effectiveness and Potential Environmental Impacts", Reprint 95-0006; SPE-29735

"Effectiveness and Potential Environmental Impacts of Biocides and Corrosion Inhibitors in the Natural Gas Industry", GRI-94/0321

"Investigation of Internal MIC and Testing Mitigation Measures (Field Guide)", GRI-92/0005

"Microbiologically Influenced Corrosion of Gas Transmission Pipelines", AGA-OSP-92-DT-66

"Role of Iron Sulfide in Microbially Influenced Corrosion of Pipelines", GRI-95/0242

"State-of-the-Art Report on Monitoring, Prevention, and Mitigation of Microbiologically Influenced Corrosion in the Natural Gas Industry", GRI-92/0382

INCORRECT OPERATION COMPANY PROCEDURE (IO)

Taylor, H.F., "Fiber Optic Pressure Sensor Development", A.G.A. Catalog No. L51724A, PR-219-9225 (January 1995).

Fletcher, C., et al, "Field Application of Electronic Gas Admission with Cylinder Pressure Feedback for Large Bore Engines", A.G.A. Catalog No. L51754, PR-239-9438 (June 1996).

Willson, B., "State of the Art Intelligent Control for Large Engines", A.G.A. Catalog No. L51756, PR-179-9131 (September 1996).

Berthold, J.W., "Fiber Optic Strain Monitoring of Pipelines", A.G.A. Catalog No. L51778, PR-255-9616 (1998).

Nessim, M.A. and Pandey, M.D., "Reliability Based Planning of Inspection & Maintenance", A.G.A. Catalog No. L51765, PR-224-9519 (January 1997).

Muhlbauer, W. Kent, *Pipeline Risk Management Manual*, Gulf Publishing Company (1992). Second Edition (1996). Also *Pipeline Risk Controller*, Version 2.0 for Windows®

Kulkarni, R.B. and Conroy, J.E., "Pipeline Inspection and Maintenance Optimization System (PIMOS)", *Pipeline Risk Assessment, Rehabilitation and Repair Conference* (September 12-15, 1994).

Kirkwood, M.G. and Karam, M., "A Scheme for Setting Pipeline Repair, Maintenance and Inspection Priorities", *Pipeline Risk Assessment, Rehabilitation and Repair Conference* (September 12-15, 1994).

Stephens, M.J. and Nessim, M.A., "Pipeline Maintenance Planning Based on Quantitative Risk Analysis", *International Pipeline Conference - Volume 1*, ASME (1996).

Kiefner, J.F., Morris, W.G., Vieth, P.H., and Wiegele, E.J., "A Risk Management Tool for Establishing Budget Priorities", *6th International Conference & Exhibition on GIS for the Oil & Gas Industry* (September 8-10, 1997).

Beighle, B. D. and Gloven, M. P., "Relative Risk - "The Competitive Advantage"", *International Pipeline Conference - Volume I*, ASME (1998).

Acton, M. R., Baldwin, P. J., Baldwin, T. R., and Jager, N. V., "The Development of the PIPESAFE Risk Assessment Package for Gas Transmission Pipelines", *International Pipeline Conference - Volume I*, ASME (1998).

Hartford Steam Boiler Inspection and Insurance Company and Radian Corporation, "Natural Gas Pipeline Risk Management, Volume I - Selected Technical Terminology", Gas Research Institute, GRI-95/0228.1 (October 1995).

Hartford Steam Boiler Inspection and Insurance Company and Radian Corporation, "Natural Gas Pipeline Risk Management, Volume II - Search of Literature Worldwide on Risk Assessment/Risk Management for Loss of Containment", Gas Research Institute, GRI-95/0228.3 (October 1995).

Hartford Steam Boiler Inspection and Insurance Company and Radian Corporation, "Natural Gas Pipeline Risk Management, Volume III - Industry Practices Analysis", Gas Research Institute, GRI-95/0228.3 (October 1995).

Hartford Steam Boiler Inspection and Insurance Company and Radian Corporation, "Natural Gas Pipeline Risk Management, Volume IV - Identification of Risk, GRI-95/0228.4 (October 1995).

Anon., "Risk Management Program Standard" (for use in the Pipeline Risk Management Demonstration Program), Produced by the Joint Risk Management Standard Team, The Office of Pipeline Safety, American Petroleum Institute, Interstate Natural Gas Association of America, National Association of Pipeline Safety Representatives, Gas Research Institute (1996).

MALFUNCTION OF CONTROL/RELIEF EQUIPMENT(MCRE)

Taylor, H.F., "Fiber Optic Pressure Sensor Development", A.G.A. Catalog No. L51724A, PR-219-9225 (January 1995).

Fletcher, C., et al, "Field Application of Electronic Gas Admission with Cylinder Pressure Feedback for Large Bore Engines", A.G.A. Catalog No. L51754, PR-239-9438 (June 1996).

Willson, B., "State of the Art Intelligent Control for Large Engines", A.G.A. Catalog No. L51756, PR-179-9131 (September 1996).

MISCELLANEOUS (MISC)

"GRI Pipeline Simulation Facility: Flow Loop", GRI-94/0379

Southwest Research Institute, "Investigation of Amine Induced Stess Corrosion Cracking of Steels in Natural Gas Treatment Plants", Catalog No. L51603, PR-15-633 (October 1989).

Van der Veer, J. and van Wortel, J.C., "Non-Destructive Assurance of Quality of Heat Treated Fittings", Catalog No. L51758, PR-238-9502 (March 1997).

Rodabaugh, E.C. and Eiber, R.J., "Pressure Capacity of MSS SP-75 Fittings", Catalog No. L51721, Report 214 (January 1995).

Groeneveld, T.P., "Quality Assurance of MSS SP-75 Fittings", Catalog No. L51744, Report 215 (September 1996).

Metallurgical Consultants, Inc., "Recommended Practice for Sour-Service Piping Components", Catalog No. L51789, PR-252-9605 (June 1995).

Fowler, J.R. and Alexander, C.R., "Design Guidelines for High-Strength Pipe Fittings", Catalog No. L51704, PR-201-9320 (January 1984).

Bubenik, T. A., Nestleroth, J. B., and Koenig, M. J., "GRI Pipeline Simulation Facility Pull Rig", GRI 94/0377 (1995).

Nestleroth, J. B, Bubenik, T. A. and Teitsma, A., "GRI Pipeline Simulation Facility Magnetic Flux Leakage Test Bed Vehicle", GRI Research Institute, GRI 96/0207 (June1996).

Bubenik, T. A. and Detty, D. W., "GRI Pipeline Simulation Facility Flow Loop", Gas Research Institute, GRI 99/0051 (January 1999).

PREVIOUSLY DAMAGED PIPE (PDP)

Kiefner, J.F., Vieth, P., Orban, J., and Feder, P., "Methods Prioritizing Pipe Maintenance and Rehabilitation", Catalog No. L51631, PR-3-919 (September 1990).

Cialone, H.J., Williams, D.N., and Groeneveld, T.P., "Investigate Hydrogen-Related Failure at Mechanical Damage", Catalog No. L51621, Report 189 (September 1991).

Kiefner, J.F. and Alexander, C.R., "Repair of Line Pipe with Dents and Scratches", Catalog No. L51788, PR-218-9508 (March 1999).

Crouch, A.E., "Assessment of NDT Needs for Pipeline Integrity Assurance II", Catalog No. L51747, PR-15-9507 (June 1995).

Rosenfield, M.J., "Development of a Model for Fatigue Rating Shallow Unrestrained Dents", Catalog No. L51741, PR-218-9405 (September 1997).

Lank, A. and Mudge, P., "Development of Long Range Ultrasonic Methods of Assessing Pipeline Condition (Phase 4)", Catalog No. L51785, PR-164-9207 (September 1995).

McDermott Technology, "Fiber Optic Strain Monitoring of Pipelines", Catalog No. L51778, PR-255-9616 (1998).

Fowler, J.R., et al, "Cyclic Pressure Fatigue Life of Pipelines with Plain Dents, Dents with Gouges, and Dents with Welds (Volume A)". Catalog No. L51705A, PR-201-9324 (June 1994).

Fowler, J.R., et al, "Cyclic Pressure Fatigue Life of Pipelines with Plain Dents, Dents with Gouges, and Dents with Welds (Volume B)", Catalog No. L51705B, PR-201-927 (June 1994).

Baley, E.I. and Read, S.R., "Damage Assessment Tool", Catalog No. L51700, PR-201-9112 (January 1993).

Fowler, J.R. and Curington, D., "Determination of Clamp Repairable Leaks", Catalog No. L51701, PR-201-9114 (January 1993).

Stress Engineering Services, Inc., "Development of a Diverless Pipeline Repair Clamp, Phase II", Catalog No. L51669, PR-201-019 (April 1992).

H.O. Mohr Research & Engineering, "Diver Assisted Repair Manual", Catalog No. L51679, PR-209-9122 (December 1992).

Miller, J.E., "Diverless Pipeline Repair Clamp I", Catalog No. L51659, PR-201-019 (August 1993).

Miller, J.E., "Diverless Pipeline Repair Clamp, Phase III", Catalog No. L51699, PR-201-019 (August 1993).

Rosenfeld, M.J., "Guidelines for the Assessment of Dents on Welds", Catalog No. L51810, PR-218-9822 (December 1999).

Muhlbauer, W. Kent, *Pipeline Risk Management Manual*, Gulf Publishing Company (1992). Second Edition (1996). Also *Pipeline Risk Controller*, Version 2.0 for Windows®

Kulkarni, R.B. and Conroy, J.E., "Pipeline Inspection and Maintenance Optimization System (PIMOS)", *Pipeline Risk Assessment, Rehabilitation and Repair Conference* (September 12-15, 1994).

Kirkwood, M.G. and Karam, M., "A Scheme for Setting Pipeline Repair, Maintenance and Inspection Priorities", *Pipeline Risk Assessment, Rehabilitation and Repair Conference* (September 12-15, 1994).

Stephens, M.J. and Nessim, M.A., "Pipeline Maintenance Planning Based on Quantitative Risk Analysis", *International Pipeline Conference - Volume 1*, ASME (1996).

Kiefner, J.F., Morris, W.G., Vieth, P.H., and Wiegele, E.J., "A Risk Management Tool for Establishing Budget Priorities", *6th International Conference & Exhibition on GIS for the Oil & Gas Industry* (September 8-10, 1997).

Beighle, B. D. and Gloven, M. P., "Relative Risk - "The Competitive Advantage"", *International Pipeline Conference - Volume I*, ASME (1998).

Acton, M. R., Baldwin, P. J., Baldwin, T. R., and Jager, N. V., "The Development of the PIPESAFE Risk Assessment Package for Gas Transmission Pipelines", *International Pipeline Conference - Volume I*, ASME (1998).

Hartford Steam Boiler Inspection and Insurance Company and Radian Corporation, "Natural Gas Pipeline Risk Management, Volume I - Selected Technical Terminology", Gas Research Institute, GRI-95/0228.1 (October 1995).

Hartford Steam Boiler Inspection and Insurance Company and Radian Corporation, "Natural Gas Pipeline Risk Management, Volume II - Search of Literature Worldwide on Risk

Assessment/Risk Management for Loss of Containment", Gas Research Institute, GRI-95/0228.3 (October 1995).

Hartford Steam Boiler Inspection and Insurance Company and Radian Corporation, "Natural Gas Pipeline Risk Management, Volume III - Industry Practices Analysis", Gas Research Institute, GRI-95/0228.3 (October 1995).

Hartford Steam Boiler Inspection and Insurance Company and Radian Corporation, "Natural Gas Pipeline Risk Management, Volume IV - Identification of Risk, GRI-95/0228.4 (October 1995).

Anon., "Risk Management Program Standard" (for use in the Pipeline Risk Management Demonstration Program), Produced by the Joint Risk Management Standard Team, The Office of Pipeline Safety, American Petroleum Institute, Interstate Natural Gas Association of America, National Association of Pipeline Safety Representatives, Gas Research Institute (1996).

Hopkins, P., "The Significance of Mechanical Damage in Gas Transmission Pipelines", Paper No. 25, NG-18/EPRG *8th Biennial Joint Technical Meeting on Line Pipe Research*, Paris (May, 1991).

Hopkins, P., Corder, I., and Corbin, P., "The Resistance of Gas Transmission Pipelines to Mechanical Damage", *International Conference on Pipeline Reliability*, Calgary (June 1992).

Corder, I. and Corbin, P., “Resistance of Pressurized Pipelines to Outside Force Damage”, Paper No. 24, NG-18/EPRG *8th Biennial Joint Technical Meeting on Line Pipe Research*, Paris (May 1991).

Francini, R. B., Hyatt, R. W., Leis, B. N., Narendran, V. K., Pape, D., and Stulen, F. B., "Real-Time Monitoring to Detect Third-Party Damage", Gas Research Institute, Report No. 96/0077 (March 1996).

Bubenik, T. A., Nestleroth, J. B., Davis, R. J., Crouch, A., Udpa, S., and Afzal, M. A., "In-Line Inspection Technologies for Mechanical Damage and SCC in Pipelines Final Report on Tasks 1 and 2", U.S. Department of Transportation, Office of Pipeline Safety, Lloyd Ultrich Contracting Officer and Technical Representative, Report No. DTRS56-96-C-00l0 (1998).

Crouch, A. E., Bruton, F. A., and Bartlett, G. R., "In-Line Inspection of Unpiggable Natural Gas Pipelines", Topical Report, GRI 95/0323, 86 pages (October 1995).

Davis, R. J, Bubenik, T. A., and Crouch, A. E., "The Feasibility of Magnetic Flux Leakage In-Line Inspection as a Method to Detect and Characterize Mechanical Damage" Topical Report GRI 95/0369 (1996).

Crouch, A. E., "In-Line Inspection of Natural Gas Pipelines", Topical Report, GRI 91-0365 (May 1993).

Anderson, H. A., Price, P. St. J., Smith, J. W. K., and Wade, R. L., "High-Accuracy Caliper Surveys with the "Geopig" Pipeline Internal Geometry Tool", *Pipeline Pigging and Inspection Technology Conference*, 20 pages (1991).

Keating, P. B., and Hoffman, R. L., "Fatigue Behavior of Dented Petroleum Pipelines - Task 4 USDOT RSPA", Contract No. DTRS56-95-C-0003 (May 1997).

Leis, B. N., Francini, R. B., Mohan, R., Rudland, D. L., and Olson, R. J., "The Pressure-Displacement Response of Gas Transmission Pipelines Under Outside Forces -- Towards a Serviceability Criterion for Mechanical Damage", Paper No. 25, PRCI-EPRG *11th Joint Technical Meeting*, Arlington (April 1997).

Roovers, P., Steiner, M., and Zarea, M., "EPRG Recommendations for the Assessment of the Tolerance and Resistance of Pipelines to External Damage", Paper No. 21, PRCI-EPRG *11th Joint Technical Meeting*, Arlington (April 1997).

Eiber, R. J., and Leis, B. N., "Line Pipe Resistance to Outside Force", Paper No. 14, EPRG/PRC *10th Joint Technical Meeting* (April 1995).

Corder, I., and Chatain, P., "EPRG Recommendations for the Assessment of the Resistance of Pipelines to External Damage", Paper No. 12, EPRG/PRC *10th Joint Technical Meeting* (April, 1995).

Corder, I., and Chatain, P., "Towards EPRG Recommendations for the Assessment of the Tolerance and Resistance of Pipelines to External Damage", Paper No. 13, EPRG/PRC *10th Joint Technical Meeting* (April 1995).

Nestleroth, J. B., and Davis, R. J., "Stress, Cold Work, and Metal-Loss Induced Magnetic Flux Leakage Signals", Paper No. 15, PRCI-EPRG *11th Joint Technical Meeting*, Arlington (April 1997).

Zarea, M., Champavére, R., Dezobry, J., Philibert, C., Chappanera, A., Dodi, F., Linke, G., and Engel, A., "The Pipe-Aggression Rig: A Comprehensive Means for Studying Pipe Resistance to Third Party Damage", Paper No. 22, PRCI-EPRG *11th Joint Technical Meeting*, Arlington (April 1997).

Zarea, M., Dea, I., and Philibert, C., "Full Scale Experimental Approach of Gas Transmission Pipeline Resistance to Dynamic Puncture", Paper No. 23, PRCI-EPRG *11th Joint Technical Meeting*, Arlington (April 1997).

Alexander, C. R., and Kiefner, J. F., "Effects of Smooth and Rock Dents on Liquid Petroleum Pipelines", API Publication 1156 (November 1997).

Hagawara, N., and Oguchi, N., "Fatigue Behavior of Line Pipes Subjected to Severe Mechanical Damage", *Proc. International Pipeline Conference*, Calgary (June 1998).

Rosenfeld, M. J., Porter, P. C., and Cox, J. C., "Strain Estimation Using VETCO Deformation Tool Data", *Proc. International Pipeline Conference*, Calgary (June 1998).

Kiefner, J. F., and Alexander, C. R., "Effects of Smooth and Rock Dents on Liquid Petroleum Pipelines (Phase 2)", Addendum to API Publication 1156, (1999).

Ferry, K. R., Rutherford, W. C., Harrison, M. R., and Shires, T. M., "Analysis of External Force Damage to Onshore Natural Gas Transmission Pipelines", Topical Report for Gas Research Institute, Report No. 98/0083 (June 1998).

Kiefner, J. F., "Effectiveness of Various Means of Preventing Pipeline Failures from Mechanical Damage", Contract No. 5015, Draft to GRI 99/0050, 35 pp (February 2000).

Anon, "Common Ground: Study of One-Call Systems and Damage Prevention Best Practices", Sponsored by the United States Department of Transportation; Research and Special Programs Administration; Office of Pipeline Safety, as authorized by the Transportation Equity Act for the 21st Century (June 1999).

REPAIRS (R)

"Evaluation of Plexus MA440(TM) Adhesive and Typical Pipeline Rehabilitation Coatings for Use with the ClockSpring™ System", GRI-98/0151

"Long-Term Durability of the ClockSpring™ System", GRI-98/0150

"Field Validation of Composite Repair of Gas Transmission Pipelines", GRI-98/0032

"Evaluation of a Composite System for Repair of Mechanical Damage in Gas Transmission Lines [CD=ROM]", GRI-97/0413

"Recommended Procedures for ClockSpring™ Field Monitoring", GRI-97/0304

"Engineering Properties of ClockSpring™ for Repair of Defects in Transmission Pipelines", GRI-95/0072

"ClockSpring™ Reinforcement of Elbow Fittings", GRI-93/0346

"Evaluation of a New Ditch Backfill Method for Use When Laying Pipelines in Rocky Terrain", GRI-97/0260

"Evaluation of Repair of Mechanical Damage in Line Pipe with ClockSpring™", GRI-96/0084

"Factors Affecting Pipeline Flaw Detection and Measurement", GRI-99/0082

"Feasibility of Ultrasonic Guided Waves for Non-Destructive Evaluation of Gas Pipelines", GRI-99/0076

"Field Validation of Composite Repair of Gas Transmission Pipelines", GRI-94/0139

"Repair of Pipeline Dents Containing Minor Scratches", GRI-99/0138 PR-218-0508

RISK MANAGEMENT/INTEGRITY MANAGEMENT (RM/IM)

"Operational Risk Management: 1996 Papers and Presentations", GRI-97/0061

"Development of the B31.8 Code and Federal Pipeline Regulations: Implications for Today's Natural Gas Pipeline System, Volume 1: Technical Report", GRI-98-0367.1

"National Pipeline Mapping System – Review of Standards Revised as of May 1998", GRI-98/0241

"Cost Benefit Study of Remote Controlled Main Line Valves", GRI-98/0076

"Review of Suggested National Pipeline Mapping System Standards", GRI-97/0411

"Integrated Spatial Analysis Techniques", GRI-97/0072

"Assessment of Remote Sensor Systems for Monitoring Pipeline Integrity, Appendix B: Field Report on Aerial Detection of Pipeline Lekage Plumes", GRI-97/0409.1

"Incident Reporting and Trending System", GRI-97/0101

"Airborne Pipeline Integrity Monitoring", GRI-95/0504

"Development of a Pipeline Inspection and Maintenance Optimization Program", GRI-95/0181

Hartford Steam Boiler Inspection and Insurance Company and Radian Corporation, "Natural Gas Pipeline Risk Management, Volume I - Selected Technical Terminology", Gas Research Institute, GRI-95/0228.1 (October 1995).

Hartford Steam Boiler Inspection and Insurance Company and Radian Corporation, "Natural Gas Pipeline Risk Management, Volume II - Search of Literature Worldwide on Risk Assessment/Risk Management for Loss of Containment", Gas Research Institute, GRI-95/0228.3 (October 1995).

Hartford Steam Boiler Inspection and Insurance Company and Radian Corporation, "Natural Gas Pipeline Risk Management, Volume III - Industry Practices Analysis", Gas Research Institute, GRI-95/0228.3 (October 1995).

Hartford Steam Boiler Inspection and Insurance Company and Radian Corporation, "Natural Gas Pipeline Risk Management, Volume IV - Identification of Risk", GRI-95/0228.4 (October 1995).

"Assessment of Remote Sensor Systems for Monitoring Pipeline Integrity", GRI-97/0409

"Assuring the Integrity of Natural Gas Transmission Pipelines, GRI-91/0366

"Development of a Pipeline Inspection and Maintenance Optimization Program", GRI-97/0245

"Development of the B31.8 Code and Federal Pipeline Regulations: Implications for Today's Natural Gas Pipeline System", Volume 1: Technical Report, GRI-98/0367.1

"Effects of Velocity on Magnetic Flux Leakage Inspection of Gas Pipelines", GRI-95/0008

"Elastic Wave Development Programme for Canadian Energy Pipeline Association", GRI-00/0159

"Environmental Aspects of Hydrostatic Test Water Discharges: Operations, Characterization, Treatment and Disposal", GRI-96/0059

"Evaluation of a New Aerial Leak Survey Approach", GRI-96/0376

"Magnetic Flux Leakage (MFL) Technology for Natural Gas Pipeline Inspection", GRI-00/0180

"Magnetic Flux Leakage Inspection of Gas Pipelines: Experience with a Collapsible Tool", GRI-96/0223

"Modification of the WaveForm Analyzer/Pulse Generator System for Close Interval Potential Survey", GRI-92/0332

"Natural Disasters and the Gas Pipeline System", GRI-96/0385

"Natural Gas Jet Flames", GRI-97/0123

"New Way of Managing Risk", GRI-96/0162

"Use of Geographic Information Systems for Applications on Gas Pipeline Rights-of-Way", GRI-92/0059

SAFETY PERFORMANCE (SP)

"Safety Performance of Natural Gas Transmission and Gathering Systems", GRI-00/0077

"Arrest of Propagating Brittle Cracks in Low Toughness Pipe with Clock Spring Reinforcements", GRI-93/0347

"Determining the Yield Stress of In-Service Transmission Pipelines", GRI-99/0284

"Effects of Line Pressure Stress, Magnetic Properties and Test Conditions on Magnetic Flux Leakage Signale", GRI-96/0197

"Fundamental Advances for Characterizing Cathodic Protection Systems", GRI-95/0064

"Fusion of Two Electromagnetic Field Sensor Technologies for Application to the Location of Buried Gas Pipes", GRI-95/0288

"Gas Transmission Industry Automation: Towards the Real Time Pipeline", Volume 2-Final Report, GRI-93/0228.2

"GRI Nondestructive Evaluation Program", GRI-92/0141

"Non-Destructive Methods for Inspectionof Gas Pipes in Gas Piping Systems", GRI-95/0477

"Nondestructive Measurement of the Ductile-to-Brittle Transition Temperature in Pipe Steels", GRI-98/0182

"Pipe Proximity Warning Device for Accidental Damage Prevention", GRI-92/0179

"Remote and Automatic Main Line Valve Technology Assessment",
GRI-95/0101 SWRI-04-6609

"Rights-of-Way (ROW) Best Management Practices (BMP) Literature and Regulatory Review: Phase I", GRI-99/0033

"Seismic Signal Processing for the Detection of Gas Pipelines and Leaks Using Ground Penetrating Radar", GRI-99/0112

"Technical Summary and Database for Guidelines for Pipelines Crossing Railroads and Highways", GRI-91/0285

STRESS-CORROSION CRACKING (SCC)

Beavers, J.A., "Assessment of the Effects of Surface Preparations and Coatings on the Susceptibility of Line Pipe to Stress Corrosion Cracking", A.G.A. Catalog No. L51666, PR-186-917 (February 1992).

Leis, B.N., "Characterization of Axial Flaws in Pipelines, with a Focus on Stress Corrosion Cracking", A.G.A. Catalog No. L51807, Report 212 (December 1997).

Perdomo, J.J. and Payer, J.H., "Chemical and Electrochemical Conditions on Steel at Disbonded Coatings", A.G.A. Catalog No. L51736, PR-75-9310 (June 1995).

Parkins, R.N., "Effects of Hydrogen on Low-pH Stress Corrosion Crack Growth", A.G.A. Catalog No. L51806, PR-232-9704 (July 1998).

Leis, B.N. and Mohan, R., "Failure Criterion for Stress-Corrosion Cracking in Pipelines", A.G.A. Catalog No. L51803, PR-3-9407 (September 1995).

Zheng, W., Revie, R., MacLeod, F., and Dinardo, O., "Low pH SCC: Environmental Effects on Crack Propagation", A.G.A. Catalog No. L51791, PR-230-9413 (July 1998).

Nunez, S., Coulson, K., Choate, .C., and Banach, J.L., "Review of Gas Industry Pipeline Coating Practices", Catalog No. L51586 (July 1988).

Leis, B.N., Forte, T.P., and Ghadiali, N.D., "Stress Corrosion Cracking Life Prediction Model (SCCLPM) Version 1.0 User's Manual and Software", Catalog No. L51808, Report 217 (November 1995).

Parkins, R.N., "Environment Sensitive Cracking of Hi-Pressure Pipe with Carbon Dioxide-Containing Solutions", Catalog No. L51683, Report 205 (September 1992).

Parkins, R.N., "Environmental Sensitive Cracking (Low pH SCC) of Hi-Pressure Pipelines", Catalog No. L51623, Report 191 (August 1990).

Beavers, J.A. and Hagerdorn, E.L., "Low-pH SCC: Mechanical Effects on Crack Propagation", Catalog No. L51760, PR-186-9402 (September 1996).

Parkins, R.N., "Overview of Intergranular SCC Research Activities", Catalog No. L51719, PR-232-9401 (November 1994).

Parkins, R.N., "Stress Corrosion Cracking of Pipelines in Contact with Near-Neutral Solutions", Catalog No. L51742, PR-232-9501 (July 1995).

Crouch, A.E., "Assessment of NDT Needs for Pipeline Integrity Assurance II", Catalog No. L51747, PR-15-9507 (June 1995).

Barton, A.B., Card, K.J., Pope, C.W., Thompson, N., and Lawson, K., "Development of Inspection Vehicle to Detect SCC in Natural Gas Lines", Catalog No. L51695, PR-198-9108 (November 1993).

Nestleroth, J.B., "Evaluation of Circumferential Magnetic Flux for In-Line Detection of Stress Corrosion Cracks and Selective Seam Weld Corrosion", Catalog No. L51811, PR-3-9420 (September 1999).

Hayford, D.T. and Davis, R.J., "In-Line Inspection Device to Detect and Size Stress Corrosion Cracks Utilizing Low Frequency Eddy Currents in Combination with Magnetic Saturation of the Pipe Wall in Natural Gas Pipelines", Catalog No. L51674, PR-3-025

Nestleroth, J.B., "Remote Field Eddy Current Detection of SCC II", Catalog No. L51657, PR-3-823 (June 1995).

Bubenik, T. A., Nestleroth, J. B., Davis, R. J., Crouch, A., Udpa, S., and Afzal, M. A., "In-Line Inspection Technologies for Mechanical Damage and SCC in Pipelines□Final Report on Tasks 1 and 2", U.S. Department of Transportation, Office of Pipeline Safety, Lloyd Ultrich Contracting Officer and Technical Representative, Report No. DTRS56-96-C-00l0 (1998).

Stirling, D. G., "Evaluation of Coating Condition Using the Elastic Wave Pig", Final Report, GRI 97/0073, 29 pages (1997).

Willems, H. H., and Barbian, O. A., "Crack Detection in Pipelines: Survey Experience Obtained with the Ultrascan CD Tool", *The Pipeline Pigging Conference*, 9 pages (February 14-16, 1996).

Willems, H. H., Barbian, O. A., and Uzelac, N. I., "In-Line Inspection Tools for Crack Detection in Gas and Liquid Pipelines", *International Pipeline Conference*, Volume 1, ASME, 8 pages (1998).

Ward, C. R., and Mann, A. S., "Field Evaluation of British Gas Elastic Wave Inspection System for SCC Detection", *Eighth Symposium on Line Pipe Research*, A.G.A. Pipeline Research Committee, Catalog No. L51680, 13 pages (1993).

"Application of New Experimental Methods to Pipeline Stress Corrosion Cracking", GRI-94/0327

"Assessment of Technology for Detection of Stress Corrosion Cracking in Gas Pipelines", GRI-94/0145

"Development of an EMAT Based In-Line Inspection System for the Detection of Stress Corrosion Cracks in Operations Pipelines", GRI-00/0184

"Effect of Microstructure and Microchemistry on the SCC Behavior of Pipeline Steels in a High pH Environment", GRI-00/0099

"Field Evaluation of the British Gas Elastic-Wave Vehicle for Detecting Stress Corrosion Cracking in Natural Gas Transmission Pipelines", GRI-95/0241

"Stress Corrosion Cracks in Pipelines: Characteristics and Detection Considerations", GRI-95/0007

SEAL/PUMP PACKING FAILURE (SPPF)

Cooke, L., "100,000 Hour Design Life of Turbo Compressor Packages", A.G.A. Catalog No. L51783, PR-253-9622 (June 1995).

Howard, T., Kantamaneni, R., and Jones, G., "Cost Effective Leak Mitigation at Natural Gas Transmission Compressor Stations", A.G.A. Catalog No. L51802, PR-246-9526 (August 1999).

THIRD-PARTY DAMAGE (TPD)

"Excavation Damage: Safety Control Study", GRI-98/0319

"Analysis of External Force Damages to Onshore Natural Gas Transmission Pipelines", GRI-98/0083

"'One Call' Centers: Survey Results, Analysis, and Recommendations", GRI-97/0412

"Assessment of Remote Sensor Systems for Monitoring Pipeline Integrity", GRI-97/0409

"Satellite Pipeline Integrity Monitoring", GRI-96/0023

Kiefner, J.F., Vieth, P., Orban, J., and Feder, P., "Methods Prioritizing Pipe Maintenance and Rehabilitation", Catalog No. L51631, PR-3-919 (September 1990).

Rosenfeld, M.J., "Pipeline In-Service Relocation Engineering Manual", Catalog No. L51717, PR-218-9308 (December 1994).

Berthold, J.W., "Fiber Optic Strain Monitoring of Pipelines", Catalog No. L51778, PR-225-9616 (1998).

Watson, P.D., "Installation of Pipelines by Horizontal Directional Drilling - Enginerring Design Guide", Catalog No. L51730, PR-227-9424 (April 1995).

Meloy, J.D., "Precision Gas Pipeline Location--A Technology Study (Volume A)", Catalog No. L51702A, PR-215-9130 (January 1994).

Baley, E.I. and Read, S.R., "Precision Gas Pipeline Location--A Technology Study (Volume B)", Catalog No. L51702B, PR-215-9130 (January 1994).

Stewart, H. E., Ingraffea, R. R., O'Rourke, T. D., and Behn, "Design of Uncased Pipelines at Railroad and Highway Crossings", *API Pipeline Conference*, Houston, Texas (April 7-8, 1992)

Kiefner, J. F., Wall, T. T., Ghadiali, N. D., Prabhat, K., and Rodabaugh, E. C., "Guidelines for Lowering Pipelines While in Service," Battelle Report to USDOT/OPS, ASME, and API, Report No. DOT-RSPA-DMT-30/84/8, NTIS, Springfield, Virginia (February 25, 1985).

Muhlbauer, W. Kent, *Pipeline Risk Management Manual*, Gulf Publishing Company (1992). Second Edition (1996). Also *Pipeline Risk Controller*, Version 2.0 for Windows®

Kulkarni, R.B. and Conroy, J.E., "Pipeline Inspection and Maintenance Optimization, System (PIMOS)", *Pipeline Risk Assessment, Rehabilitation and Repair Conference* (September 12-15, 1994).

Kirkwood, M.G. and Karam, M., "A Scheme for Setting Pipeline Repair, Maintenance and Inspection Priorities", *Pipeline Risk Assessment, Rehabilitation and Repair Conference* (September 12-15, 1994).

Stephens, M.J. and Nessim, M.A., "Pipeline Maintenance Planning Based on Quantitative Risk Analysis", *International Pipeline Conference - Volume 1*, ASME (1996).

Kiefner, J.F., Morris, W.G., Vieth, P.H., and Wiegele, E.J., "A Risk Management Tool for Establishing Budget Priorities", *6th International Conference & Exhibition on GIS for the Oil & Gas Industry* (September 8-10, 1997).

Beighle, B. D. and Gloven, M. P., "Relative Risk - "The Competitive Advantage"", *International Pipeline Conference - Volume I*, ASME (1998).

Acton, M. R., Baldwin, P. J., Baldwin, T. R., and Jager, N. V., "The Development of the PIPESAFE Risk Assessment Package for Gas Transmission Pipelines", *International Pipeline Conference - Volume I*, ASME (1998).

Hartford Steam Boiler Inspection and Insurance Company and Radian Corporation, "Natural Gas Pipeline Risk Management, Volume I - Selected Technical Terminology", Gas Research Institute, GRI-95/0228.1 (October 1995).

Hartford Steam Boiler Inspection and Insurance Company and Radian Corporation, "Natural Gas Pipeline Risk Management, Volume II - Search of Literature Worldwide on Risk Assessment/Risk Management for Loss of Containment", Gas Research Institute, GRI-95/0228.3 (October 1995).

Hartford Steam Boiler Inspection and Insurance Company and Radian Corporation, "Natural Gas Pipeline Risk Management, Volume III - Industry Practices Analysis", Gas Research Institute, GRI-95/0228.3 (October 1995).

Hartford Steam Boiler Inspection and Insurance Company and Radian Corporation, "Natural Gas Pipeline Risk Management, Volume IV - Identification of Risk, GRI-95/0228.4 (October 1995).

Anon., "Risk Management Program Standard" (for use in the Pipeline Risk Management Demonstration Program), Produced by the Joint Risk Management Standard Team, The Office of Pipeline Safety, American Petroleum Institute, Interstate Natural Gas Association of America, National Association of Pipeline Safety Representatives, Gas Research Institute (1996).

Hopkins, P., "The Significance of Mechanical Damage in Gas Transmission Pipelines", Paper No. 25, *NG-18/EPRG 8th Biennial Joint Technical Meeting on Line Pipe Research*, Paris (May, 1991).

Hopkins, P., Corder, I., and Corbin, P., "The Resistance of Gas Transmission Pipelines to Mechanical Damage", *International Conference on Pipeline Reliability*, Calgary (June 1992).

Corder, I. and Corbin, P., "Resistance of Pressurized Pipelines to Outside Force Damage", Paper No. 24, NG-18/EPRG *8th Biennial Joint Technical Meeting on Line Pipe Research*, Paris (May 1991).

Chatain, P., "An Experimental Evaluation of Punctures and Resulting Dents in Gas Transmission Pipelines", Paper No. 15, PRC/EPRG *9th Joint Technical Meeting on Line Pipe Research*, 12 pp (May 1993).

Chatain, P., "An Experimental Evaluation of Punctures and Resulting Dents in Transmission Pipelines", Paper No. 11, *8th Symposium on Line Pipe Research*, (September 1993).

Francini, R. B., Hyatt, R. W., Leis, B. N., Narendran, V. K., Pape, D., and Stulen, F. B., "Real-Time Monitoring to Detect Third-Party Damage", Gas Research Institute, Report No. 96/0077 (March 1996).

Roovers, P., Steiner, M., and Zarea, M., "EPRG Recommendations for the Assessment of the Tolerance and Resistance of Pipelines to External Damage", Paper No. 21, PRCI-EPRG *11th Joint Technical Meeting*, Arlington (April 1997).

Zarea, M. F., Toumbas, D. N., and Phlibat, C. C., "Numerical Models for Static Denting and Dynamic Puncture of Gas Transmission Linepipe and Their Validation", *Proc. 1st International Pipeline Conference*, Calgary (June 1996).

Eiber, R. J., and Leis, B. N., "Line Pipe Resistance to Outside Force", Paper No. 14, EPRG/PRC *10th Joint Technical Meeting* (April 1995).

Corder, I., and Chatain, P., "EPRG Recommendations for the Assessment of the Resistance of Pipelines to External Damage", Paper No. 12, EPRG/PRC *10th Joint Technical Meeting* (April, 1995).

Corder, I., and Chatain, P., "Towards EPRG Recommendations for the Assessment of the Tolerance and Resistance of Pipelines to External Damage", Paper No. 13, EPRG/PRC *10th Joint Technical Meeting* (April 1995).

Zarea, M., Champavére, R., Dezobry, J., Philibert, C., Chappanera, A., Dodi, F., Linke, G., and Engel, A., "The Pipe-Aggression Rig: A Comprehensive Means for Studying Pipe Resistance to Third Party Damage", Paper No. 22, PRCI-EPRG *11th Joint Technical Meeting*, Arlington (April 1997).

Zarea, M., Dea, I., and Philibert, C., "Full Scale Experimental Approach of Gas Transmission Pipeline Resistance to Dynamic Puncture", Paper No. 23, PRCI-EPRG *11th Joint Technical Meeting*, Arlington (April 1997).

Doctor, R. H., Dunker, N. A., and Santee, N. M., "Third-Party Damage Prevention Systems", Gas Research Institute, Report No. 95/0816 (October 1995).

Hartranft, R. M., "The One-Call Center: Survey Results, Analysis, and Recommendations", Final Report for Gas Research Institute, Report No. 97/0412 (December 1997).

Ferry, K. R., Rutherford, W. C., Harrison, M. R., and Shires, T. M., "Analysis of External Force Damage to Onshore Natural Gas Transmission Pipelines", Topical Report for Gas Research Institute, Report No. 98/0083 (June 1998).

Kiefner, J. F., "Effectiveness of Various Means of Preventing Pipeline Failures from Mechanical Damage", Contract No. 5015, Draft to GRI 99/0050, 35 pp (February 2000).

Anon, "Common Ground: Study of One-Call Systems and Damage Prevention Best Practices", Sponsored by the United States Department of Transportation; Research and Special Programs Administration; Office of Pipeline Safety, as authorized by the Transportation Equity Act for the 21st Century (June 1999).

"Signal Characterization of Mechanical Third-Party Damage", GRI-00/0030

"Third-Party Damage Prevention Systems", GRI-95/0316

THREADS STRIPPED, BROKEN PIPE COUPLING (TSBPC)

Howard, T., Kantamaneni, R., and Jones, G., "Cost Effective Leak Mitigation at Natural Gas Transmission Compressor Stations", A.G.A. Catalog No. L51802, PR-246-9526 (August 1999).

Taylor, H.F., "Development and Testing of an Advanced Technology Vibration Transmission", A.G.A. Catalog No. L51755, PR-240-9416 (July 1996).

VANDALISM (V)

Francini, R. B., Hyatt, R. W., Leis, B. N., Narendran, V. K., Pape, D., and Stulen, F. B., "Real-Time Monitoring to Detect Third-Party Damage", Gas Research Institute, Report No. 96/0077 (March 1996).

WRINKLE BEND OR BUCKLE (WBB)

Anderson, H. A., Price, P. St. J., Smith, J. W. K., and Wade, R. L., "High-Accuracy Caliper Surveys with the "Geopig" Pipeline Internal Geometry Tool", *Pipeline Pigging and Inspection Technology Conference*, 20 pages (1991).